0000173634

ORIGINAL

Transcript Exhibit(s)

Docket #(s): E-01933A-15-0239

E-01933A-15-0322

Arizona Corporation Commission
DOCKETED
SEP 29 2016

DOCKETED BY	

2016 SEP 29 AM 10 39

AZ CORP COMM
DOCKET CONTROL

Exhibit #: AECC 1-6, 8, 10, 12-14

RUCO 1-10

Part 5 of 7

For parts 1-4, see barcodes 0000173630 through 0000173633

For parts 6 + 7, see barcodes 0000173635 + 0000173636

EXHIBIT ADMITTED
AECC-1
admitted

TEP PROPOSED REVENUE ALLOCATION / RATE SPREAD
LPS Class

	Direct Testimony	Rebuttal Testimony	Rejoinder Testimony
Current Sales Revenue	$94,396,366	$91,514,743	$91,514,743
Proposed Sales Revenue	$92,408,365	$96,021,188	$96,227,517
Proposed Increase/(Dec.)	($1,988,001)	$4,506,445	$4,712,774
Class % Change	(2.1%)	4.9%	5.1%
Source:	Table KCH-3 (Adjusted)	Table KCH-SR-3	Table KCH-SR-3/ Exhibit CAJ-RJ-1 (H-1)

EXHIBIT
ADMITTED
AECC-2
admitted

TEP PROPOSED REVENUE ALLOCATION / RATE SPREAD
138kV Class

	Direct Testimony	Rebuttal Testimony	Rejoinder Testimony
Current Sales Revenue	$37,720,351	$30,466,830	$30,466,830
Proposed Sales Revenue	$36,190,904	$30,053,687	$31,062,633
Proposed Increase/(Dec.)	($1,529,447)	($413,144)	$595,803
Class % Change	(4.1%)	(1.4%)	2.0%
Source:	Table KCH-3	Table KCH-SR-3	Table KCH-SR-3/ Exhibit CAJ-RJ-1 (H-1)

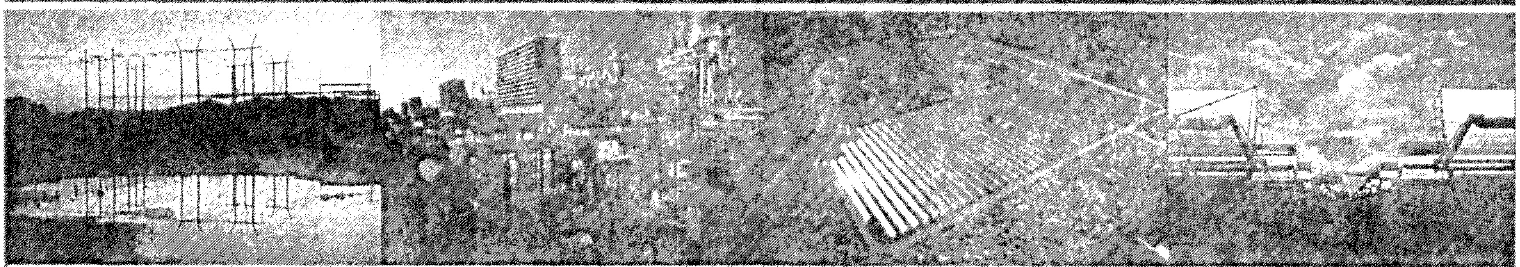
AECC -3

TEP's Recommended 138kV Target Revenue

Phase of Case	TEP Overall Revenue Increase	138 KV Target Revenue Req't	Data Source
TEP - Rebuttal	$100,668,471	$30,053,687	2015 TEP Rev Proof CompSensitiveConfid Rebuttal WP, Worksheet H2-2.
TEP - Rejoinder	$81,500,172	$31,062,633	TEP Exhibit CAJ-RJ-1, Sch. H-2-2 Rejoinder, p. 4 of 23.

EXHIBIT
ADMITTED
AECC -3
admitted

EXHIBIT
AECC-4
admitted



Tucson Electric Power

2016 Preliminary Integrated Resource Plan

March 1, 2016

Future Load Obligations

The tables shown on the next two pages provide a data summary on TEP's loads and resources. Table 4 below shows TEP's projected firm load obligations which includes retail, firm wholesale, system losses and planning reserves.

Table 4 – Firm Load Obligations, System Peak Demand (MW)

Demand, MW	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential	1,139	1,101	1,115	1,212	1,259	1,269	1,281	1,296	1,308	1,332	1,354	1,377	1,401	1,425	1,455	1,473	1,494
Commercial	508	479	475	516	536	540	545	552	557	567	576	586	596	606	619	627	636
Industrial	485	444	443	482	500	504	509	515	520	529	538	547	557	566	578	586	594
Mining	124	292	337	366	380	383	387	392	395	402	409	416	423	430	439	445	451
Other	28	5	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6
Gross Retail Peak Demand	2,284	2,321	2,375	2,581	2,680	2,703	2,728	2,760	2,785	2,836	2,882	2,933	2,983	3,034	3,097	3,137	3,182
Distributed Generation	-32	-35	-39	-42	-45	-48	-51	-54	-56	-58	-59	-60	-62	-63	-65	-68	-69
Energy Efficiency	-143	-163	-183	-202	-221	-237	-253	-268	-283	-299	-312	-327	-341	-356	-383	-394	-411
Net Retail Peak Demand	2,109	2,122	2,153	2,336	2,414	2,417	2,424	2,439	2,446	2,479	2,512	2,546	2,580	2,615	2,650	2,676	2,702
Firm Wholesale Demand	205	251	186	186	182	182	129	129	129	44	44	44	44	44	44	0	0
System Losses	209	211	214	232	240	240	241	242	243	246	249	253	256	260	263	266	268
Total Firm Load Obligations	2,524	2,583	2,552	2,754	2,835	2,839	2,794	2,810	2,818	2,769	2,806	2,843	2,880	2,919	2,957	2,942	2,970
Reserve Margin	432	457	74	-108	-159	-144	-243	-246	-227	-166	-169	-206	-211	-244	-250	-402	-541
Reserve Margin, %	15%	15%	3%	-4%	-6%	-5%	-10%	-10%	-9%	-6%	-6%	-8%	-8%	-9%	-9%	-16%	-22%

System Resource Capacity

Table 5 shows TEP's preliminary firm resource capacity based on a resource's contribution to system peak.

Table 5 - Capacity Resources, System Peak Demand (MW)

Firm Resource Capacity (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Four Corners	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	
Navajo	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168		
San Juan	340	340	170	170	170	170											
Springerville	598	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793
Remote Coal Resources	1216	1411	1241	1241	1241	1241	1071	1071	1071	1071	1071	1071	1071	1071	1071	903	793
Sundt 1-4	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422	422
Luna Energy Facility	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
Gila River Power Station	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374
DeMoss Petrie CT	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
North Loop CT 1-4	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Sundt CT 1-2	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Total Natural Gas Resources	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Utility Scale Renewables	97	110	136	149	176	189	215	228	255	268	301	301	334	334	367	367	367
Demand Response	19	24	29	35	40	45	45	45	45	45	45	45	45	50	50	50	50
Total Renewable & EE Resources	116	134	165	184	216	234	260	273	300	313	346	346	379	384	417	417	417
Short-Term Market Resources	425	275	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Storage Resources	0	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Total Firm Resources	2956	3040	2626	2645	2677	2695	2551	2564	2591	2604	2637	2637	2670	2675	2708	2540	2430

EXHIBIT
AECC-5
admitted

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2015
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-11307-01

Freeport-McMoRan Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**74-2480931** (I.R.S. Employer Identification No.)
333 North Central Avenue **Phoenix, AZ** (Address of principal executive offices)	**85004-2189** (Zip Code)

(602) 366-8100
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
☑ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☑ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
☐ Yes ☑ No

On July 31, 2015, there were issued and outstanding 1,040,228,261 shares of the registrant's common stock, par value $0.10 per share.

Mining Unit Site Production and Delivery Costs
Site production and delivery costs for our copper mining operations primarily include labor, energy and commodity-based inputs, such as sulphuric acid, reagents, liners, tires and explosives. Consolidated unit site production and delivery costs (before net noncash and other costs) for our copper mines totaled $1.85 per pound of copper in second-quarter 2015 and $1.89 for the first six months of 2015, compared with $1.99 per pound in second-quarter 2014 and $1.94 for the first six months of 2014. Lower consolidated average site production and delivery costs for the 2015 periods, compared with the 2014 periods, primarily reflected higher copper sales volumes in North America and Indonesia, partly offset by lower sales volumes in South America. Refer to "Operations – Unit Net Cash Costs" for further discussion of unit net cash costs associated with our operating divisions and to "Product Revenues and Production Costs" for reconciliations of per pound costs by operating division to production and delivery costs applicable to sales reported in our consolidated financial statements.

Assuming achievement of current volume and cost estimates, consolidated unit site production and delivery costs are expected to be lower in the second half of 2015 and average $1.81 per pound of copper for the year 2015, which is subject to change as a result of the comprehensive review of operating plans as further discussed in "Overview."

Oil and Gas Cash Production Costs per BOE
Production costs for our oil and gas operations primarily include costs incurred to operate and maintain wells and related equipment and facilities, such as lease operating expenses, steam gas costs, electricity, production and ad valorem taxes, and gathering and transportation expenses. Cash production costs for our oil and gas operations of $19.04 per BOE in second-quarter 2015 were lower than cash production costs of $19.57 per BOE in second-quarter 2014, primarily reflecting lower cash production costs in California related to reductions in repair and maintenance costs and well workover expense, partly offset by higher average costs per BOE resulting from the sale of lower-cost Eagle Ford properties. Cash production costs of $19.62 per BOE for the first six months of 2015, were higher than $19.03 for the first six months of 2014, primarily reflecting the sale of lower-cost Eagle Ford properties, partly offset by lower cash production costs in California. Refer to "Operations" for further discussion of cash production costs at our oil and gas operations.

Assuming achievement of current volume and cost estimates for the remainder of 2015, cash production costs are expected to approximate $20 per BOE for the year 2015.

Depreciation, Depletion and Amortization
Depreciation will vary under the unit-of-production (UOP) method as a result of changes in sales volumes and the related UOP rates at our mining and oil and gas operations. Consolidated depreciation, depletion and amortization (DD&A) totaled $890 million in second-quarter 2015 and $1.8 billion for first six months of 2015, compared with $1.0 billion in second-quarter 2014 and $2.0 billion for the first six months of 2014. DD&A in the 2015 periods, compared with the 2014 periods, reflected lower expense from our oil and gas operations associated with decreased production as a result of the sale of the Eagle Ford properties. Lower DD&A from our oil and gas operations for the first six months of 2015, compared with the first six months of 2014, was partly offset by higher DD&A from our mining operations mostly associated with higher sales volumes in North America and Indonesia.

Impairment of Oil and Gas Properties
Under full cost accounting rules, a "ceiling test" is conducted each quarter to review the carrying value of our oil and gas properties for impairment. At June 30, 2015, and March 31, 2015, net capitalized costs with respect to FCX's proved U.S. oil and gas properties exceeded the related ceiling test limitation, which resulted in the recognition of impairment charges of $2.7 billion in second-quarter 2015 and $5.8 billion for the first six months of 2015, reflecting the lower twelve-month average of the first-day-of-the-month historical reference oil price and higher capitalized costs at such dates. Refer to Note 1 and "Operations - Oil and Gas" for further discussion, including discussion of potentially significant additional ceiling test impairments.

Income Taxes
Following is a summary of the approximate amounts used in the calculation of our consolidated income tax benefit (provision) for the 2015 and 2014 periods (in millions, except percentages):

	Six Months Ended June 30, 2015			Six Months Ended June 30, 2014		
	Income (Loss)[a]	Effective Tax Rate	Income Tax (Provision) Benefit	Income (Loss)[a]	Effective Tax Rate	Income Tax (Provision) Benefit
U.S.	$ (469)[b]	61%	$ 288	$ 936	31%	$ (291)[c]
South America	81	37%	(30)	747	36%	(267)
Indonesia	289	43%	(124)	(39)	38%	15
Africa	114	46%	(53)	187	30%	(57)
Impairment of oil and gas properties	(5,790)	38%	2,179	—	N/A	—
Valuation allowance	—	N/A	(763)[d]	—	N/A	—
Eliminations and other	187	N/A	(28)	138	N/A	(37)
Annualized rate adjustment[e]	—	N/A	(87)	—	N/A	(48)
Consolidated FCX	$ (5,588)	25%[f]	$ 1,382	$ 1,969	35%	$ (685)

a. Represents income (loss) by geographic location before income taxes and equity in affiliated companies' net earnings.

b. Includes a gain of $92 million related to net proceeds received from insurance carriers and other third parties related to a shareholder derivative litigation settlement for which there is no related tax provision.

c. Includes a $58 million charge for deferred taxes recorded in connection with the allocation of goodwill to the sale of Eagle Ford.

d. As a result of the impairment to oil and gas properties, we recorded a tax charge to establish a valuation allowance primarily against U.S. federal alternative minimum tax credits.

e. In accordance with applicable accounting rules, we adjust our interim provision for income taxes equal to our estimated annualized tax rate.

f. Our consolidated effective income tax rate is a function of the combined effective tax rates for the jurisdictions in which we operate. Accordingly, variations in the relative proportions of jurisdictional income result in fluctuations to our consolidated effective income tax rate. Assuming achievement of current sales volume and cost estimates and average prices of $2.50 per pound for copper, $1,150 per ounce for gold, $6 per pound for molybdenum and $56 per barrel of Brent crude oil for the second half of 2015, we estimated a tax benefit of $1.4 billion for 2015, substantially all of which relates to the impairment of oil and gas properties and resulting tax charge to establish a valuation allowance in the first half of 2015. See "Operations - Oil and Gas" for discussion regarding the likelihood of potentially significant ceiling charges during the remainder of 2015, which would give rise to additional tax benefits.

OPERATIONS

North America Copper Mines
We operate seven open-pit copper mines in North America – Morenci, Bagdad, Safford, Sierrita and Miami in Arizona, and Chino and Tyrone in New Mexico. All of the North America mining operations are wholly owned, except for Morenci. We record our 85 percent joint venture interest in Morenci using the proportionate consolidation method.

The North America copper mines include open-pit mining, sulfide ore concentrating, leaching and solution extraction/electrowinning (SX/EW) operations. A majority of the copper produced at our North America copper mines is cast into copper rod by our Rod & Refining segment. The remainder of our North America copper sales is in the form of copper cathode or copper concentrate, a portion of which is shipped to Atlantic Copper (our wholly owned smelter). Molybdenum concentrates and silver are also produced by certain of our North America copper mines.

As further discussed in "Overview," we are currently reviewing operating plans at each of our copper and molybdenum mining operations and will revise operating and capital plans to strengthen our financial position in a weak copper price environment. The revised plans will target lower operating and capital costs to achieve maximum cash flow under the current market conditions. Production at certain operations challenged by low commodity prices will be curtailed. We expect to complete this review promptly and will report our revised plans during third-quarter

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

EXHIBIT
AECC-6
ADMITTED

REDACTED

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport Minerals Corporation and

Arizonans for Electric Choice & Competition

Revenue Requirement

June 3, 2016

DIRECT TESTIMONY OF KEVIN C. HIGGINS

TABLE OF CONTENTS

DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My revenue requirement testimony is being sponsored by Freeport Minerals Corporation and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist

[1] Henceforth in this testimony, Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before this Commission in other dockets?

A. Yes. I have testified in approximately twenty proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on APS 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13] TEP's request to amend

[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.

Decision No. 62103 (2007),[14] the TEP 2007 rate case (2008),[15] the APS 2008 rate case (2008),[16] the APS 2011 rate case (2011-12),[17] the TEP 2011 Energy Efficiency Plan (2012),[18] the TEP 2012 rate case (2012),[19] the APS Four Corners Rate Rider proceeding (2014),[20] and the UNSE Electric, Inc. ("UNSE") 2015 rate case (2015).[21]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 180 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.
[17] Docket No. E-01345A-11-0224.
[18] Docket No. E-01933A-11-0055.
[19] Docket No. E-01933A-12-0291.
[20] Docket No. E-01345A-11-0224.
[21] Docket No. E-04204A-15-0142.

OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My testimony addresses three major topics concerning revenue requirement:

(1) TEP's request for a non-fuel rate increase of $109.5 million;

(2) Certain revenue requirement issues pertaining to the Purchased Power and Fuel Adjustment Charge ("PPFAC"); and

(3) TEP's proposed modifications to the Environmental Compliance Adjustment ("ECA").

In my testimony, I recommend adjustments to TEP's proposals that I believe are necessary to ensure rates that are just and reasonable.

I will address the topics of class cost-of-service, revenue allocation, buy-through service, and the Lost Fixed Cost Recovery mechanism in my Rate Design testimony.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that TEP's revenue requirement be reduced by **$48.587** million relative to the $109.5 million base rate increase proposed by the Company in its Application. My recommended adjustments are itemized in Table KCH-1, presented later in my testimony. My recommended reduction does not take into account or incorporate any other adjustments that may be offered by other parties which were not addressed in my testimony.

(2) The current PPFAC is structured to flow-through 100% of all deviations in fuel and purchased power costs to customers. This type of 100%

cost pass-through seriously reduces a utility's incentive to manage its fuel and purchased power costs as well as it would manage them if it remained exposed to the energy cost risk. In my opinion, a risk-sharing mechanism is essential to keep customer and Company interests aligned. Consequently, I recommend adoption of a 70/30 risk-sharing mechanism in the PPFAC.

(3) The PPFAC Plan of Administration was changed in the last general rate case to shift the profits realized from new long-term contracts to the benefit of TEP shareholders instead of customers. This change should be reversed going forward. Instead, all revenues from wholesale sales, irrespective of term, should be credited against fuel and purchased power costs and included in the PPFAC, unless such sales are allocated a share of system costs.

(4) The ECA is an example of unwarranted single-issue ratemaking, but was included in the Settlement Agreement package negotiated by the parties to the last general rate case, subject to a cap of 0.25% of TEP's total retail revenue. In this case, TEP is proposing to double the ECA cap. I recommend that this change be rejected. Instead, I recommend that the Commission terminate the ECA, unless it is capped at the previously-negotiated 0.25% of TEP's total retail revenue.

ADJUSTMENTS TO PROPOSED BASE REVENUE INCREASE

Q. What increase in base revenues is TEP recommending in this case?

A. In its Application, TEP is requesting a non-fuel rate increase of $109.5 million, or 12.0% over total adjusted test year revenues, to become effective no later than January 1, 2017.[22] As noted in TEP's filing, based on the PPFAC that went into effect April 2015, TEP's proposal represents a net increase of $67.3 million, or 7.1% over total adjusted test year revenues including the higher fuel component.[23] However, the current PPFAC rate effective May 1, 2016 of $0.001501 per kWh is significantly less than the April 2015 rate of $0.00682 per kWh included in TEP's analysis. Consequently, the proposed net increase relative to *present* rates is greater than the 7.1% measured by TEP using the previous PPFAC rate.

Q. Do you have any recommended adjustments to TEP's proposed base rate increase?

A. Yes. I am recommending an overall reduction of **$48.587** million to TEP's proposed base rate increase relative to the Company's Application. This recommendation is presented in Exhibit KCH-1 and is summarized in Table KCH-1 and consists of the following adjustments, each of which will be discussed in turn:

[22] Application, p. 1.
[23] Direct Testimony of Dallas J. Dukes, pp. 32-33.

Table KCH-1
Summary of AECC Adjustments to TEP Revenue Requirements

	ACC Jurisdictional Adjustment Amount (\$000s)
Rate Base Adjustments	
Bonus Tax Depreciation Extension	(\$1,525)
Sundt & San Juan 2 M&S Regulatory Asset Adjustment	(\$43)
50.5% Co-Ownership of SGS 1 Regulatory Asset Adjustment	(\$4,673)
SGS 1 2006 Lease Acquisition Rate Base Adjustment	(\$1,488)
Capitalized Legal Cost Adjustment	(\$88)
Expense Adjustments	
Legal Expense Adjustment	(\$1,343)
Payroll Expense Adjustment	(\$1,222)
Short-Term Incentive Compensation Adjustment	(\$1,972)
Long-Term Incentive Compensation Adjustment	(\$1,296)
SERP Recovery Adjustment	(\$950)
Severance Costs Adjustment	(\$218)
Credit Card Processing Fees Adjustment	(\$3,482)
Generation Overhaul Adjustment	(\$1,865)
ROE Adjustment	
Return on Equity Adjustment	(\$10,826)
Jurisdictional Allocation Adjustment	
Demand Allocation Factor	(\$14,043)
Other Cost of Capital Adjustment	
Allowed Return on New TEP Headquarters Building Adj.	(\$3,552)
Total AECC Adjustments	(\$48,587)

Bonus Tax Depreciation

Q. What is bonus tax depreciation?

A. Bonus tax depreciation refers to a greatly accelerated tax deduction for depreciation that has been permitted pursuant to several statutes signed into law in recent years to stimulate the economy. Bonus tax depreciation was permitted in the early 2000s and reintroduced in 2008 and 2009 pursuant to the Economic

Stimulus Act of 2008, and the American Recovery and Reinvestment Act of 2009. It has since been extended several times but was scheduled to end on December 31, 2014, except under certain circumstances for qualified property placed in service through December 31, 2015.

Q. Has bonus tax depreciation been extended beyond December 31, 2014?

A. Yes. The Protecting Americans from Tax Hikes Act of 2015, part of H.R. 2029, was signed into law on December 18, 2015. This Act extends 50 percent bonus tax depreciation through December 31, 2017, and includes a phase down to 40 percent bonus tax depreciation in 2018, and 30 percent in 2019.

Q. How does bonus tax depreciation impact ratemaking for regulated utilities?

A. Bonus tax depreciation is a form of accelerated tax depreciation. Regulatory authorities, including this Commission, have long recognized that utility depreciation for tax purposes differs from utility book depreciation used in ratemaking. The timing difference between tax depreciation and book depreciation is recognized through the recording of accumulated deferred income tax ("ADIT"). Generally, the tax benefits of accelerated depreciation are not passed through *directly* to ratepayers, but rather certain indirect benefits are recognized through the determination of rate base. According to the conventions of income tax normalization, the benefit of a utility's ADIT is viewed as a source of zero-cost capital to the utility as part of the ratemaking process. Consequently, the ADIT that results from accelerated tax depreciation is booked as a credit against rate base, thereby reducing revenue requirements for customers.

Even though bonus tax depreciation affects rates through the same mechanics as standard accelerated depreciation, its impact is more dramatic than standard accelerated depreciation in the years immediately following the placement of the qualifying plant into service. This is because bonus tax depreciation causes a much greater increase in ADIT, which in turn, produces a much greater credit against rate base for any given amount of new plant in service. This, in turn, reduces the revenue requirement relative to what it would have been if bonus tax depreciation were not applicable.

Q. Why is the extension of bonus tax depreciation relevant for this proceeding?

A. Bonus tax depreciation has a material impact on utility revenue requirements. TEP's rate case was filed under the assumption that bonus tax depreciation would not be available past December 31, 2014. Since it is now known that bonus tax depreciation has been extended, it is necessary to properly reflect the ratemaking impact of this tax change.

Q. Has TEP provided information regarding the revenue requirement impact of extending bonus tax depreciation?

A. Yes. Based on TEP's response to discovery, the extension of bonus tax depreciation would result in a net increase in the magnitude of Total Company ADIT, or reduction to rate base, of approximately $15.9 million relative to TEP's filed case.[24]

Q. What is your recommendation to the Commission regarding the treatment of bonus tax depreciation on TEP's revenue requirement?

A. TEP's revenue requirement should be adjusted to reflect the impact of the extension of bonus tax depreciation.

[24] TEP's Supplemental Response to AECC Data Request 1.3, Attachment AECC 1.3 Bonus - Rate Base - Accumulated Deferred Income Taxes.xlsm, provided in Exhibit KCH-18. See also Exhibit KCH-2, page 2 of 2.

Q. What is the impact on TEP's jurisdictional revenue requirement from your adjustment?

A. My adjustment to reflect the extension of bonus tax depreciation is shown in Exhibit KCH-2. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.525** million.

Sundt and San Juan Unit 2 Materials & Supplies

Q. What is TEP proposing regarding Sundt coal handling facilities ("CHF") and San Juan Unit 2 materials and supplies?

A. According to the Direct Testimony of Frank P. Marino, the Sundt CHF are no longer expected to be used and useful as of April 2016, and closure of San Juan Unit 2 is expected by December 2017.[25] TEP is proposing to record the remaining materials and supplies inventory for the Sundt CHF and San Juan Unit 2 as a regulatory asset, and to amortize the cost over a three year period.[26]

Q. Do you agree with TEP's proposed treatment of the Sundt CHF and San Juan Unit 2 materials and supplies inventory?

A. Not entirely. TEP includes the entire inventory of $1.2 million in rate base, while also including approximately $400,000 in amortization expense based on the three-year amortization period. TEP does not reflect the impact of accumulated amortization as an offset against the inventory rate base balance.[27]

Q. What do you recommend regarding the ratemaking treatment of Sundt CHF and San Juan 2 materials and supplies?

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[25] Direct Testimony of Frank P. Marino, pp. 9-10.
[26] *Id.*, p. 14, lns. 3-13.
[27] TEP's Rate Base - Sundt _ San Juan M_S adjustment workpaper; TEP's Income - Sundt _ San Juan M_S adjustment workpaper.

A. I recommend that the first year of amortization expense of approximately $400,000 be recorded as accumulated amortization, reducing the net rate base balance by the same amount. As TEP explains, the proposed three-year amortization period starts in the Test Year,[28] and TEP has included the annual amortization expense in its revenue requirement. Therefore it is appropriate to reflect the Sundt CHF and San Juan 2 materials and supplies net rate base after one year of accumulated amortization has accrued.

Q. What is the impact on TEP's jurisdictional revenue requirement from your adjustment?

A. My adjustment is shown in Exhibit KCH-3. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.043** million.

50.5% Co-Ownership of Springerville Unit 1

Q. What revenue requirement issues are you addressing regarding the 50.5% co-ownership of Springerville Unit 1?

A. At the time of TEP's Application, Springerville Unit 1 was co-owned by a third party, Alterna Springerville LLC ("Alterna"), with whom TEP had been engaged in extensive litigation. In the Company's Application and direct testimony, TEP makes a number of proposals regarding the ratemaking treatment of cost items associated with the 50.5% ownership share – proposals with which I have objections based on the circumstances existing at the time of TEP's filing. However, based on press reports published subsequent to the filing of TEP's Application in this case, it is my understanding that TEP has resolved its

[28] Direct Testimony of Frank P. Marino, p. 14, lns. 5-7, p. 42, lns 13-16.

differences with Alterna and intends to purchase Alterna's 50.5% interest. In light of these changed circumstances, TEP's proposals regarding the regulatory treatment of the costs associated with Alterna's 50.5% interest are no longer applicable. Consequently, I will not present my initial objections to these proposals. Rather, I am recommending that the special ratemaking provisions proposed by TEP to address the 50.5% co-ownership of Springerville Unit 1 be rejected because they are no longer applicable to the facts of this case. In addition, I address the legal expenses incurred by TEP in its dispute with Alterna as a separate issue in my testimony.

Q. What specific revenue requirement adjustments must be made to remove the special ratemaking provisions proposed by TEP regarding the 50.5% co-ownership of Springerville Unit 1?

A. I am aware of two distinct ratemaking treatments that TEP has proposed in this case with respect to the 50.5% co-ownership share of Springerville Unit 1. The first is the establishment of a regulatory asset in the amount of $23.9 million associated with facility improvements on the 50.5% co-ownership share.[29] The second is the inclusion of $16.291 million in non-fuel O&M expenses in the PPFAC, which would be potentially offset by wholesale margins from dispatch of the 50.5% co-ownership share of the plant.[30]

With respect to the first treatment proposed by TEP, I recommend that the requested regulatory asset should not be recognized by the Commission and the earnings on this asset and amortization expense be removed from the revenue

[29] See TEP Response to AECC Data Request 16.1, provided in Exhibit KCH-18.
[30] Direct testimony of Michael E. Sheehan, pp. 45-46.

requirement. I present this adjustment in Exhibit KCH-4. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$4.673** million.

With respect to the second treatment proposed by TEP, I recommend that the requested inclusion in the PPFAC of $16.291 million in non-fuel O&M expenses associated with the 50.5% ownership share of Springerville Unit 1 be rejected.

Q. In recommending that the Commission reject these special ratemaking proposals, are you substituting other revenue requirement adjustments to reflect TEP's acquisition of the 50.5% co-ownership share of Springerville Unit 1?

A. No. The burden for making the case and demonstrating the reasonableness of its acquisition of the 50.5% co-ownership share of Springerville Unit 1 rests with TEP. The Company has not put forward a revenue requirement proposal reflecting the acquisition of the 50.5% co-ownership share of Springerville Unit 1 at this time.

Springerville Unit 1 2006 Acquisition

Q. Please provide some basic background regarding TEP's 2006 Springerville Unit 1 lease equity purchase.

A. As explained in the direct testimony of witness Kentton Grant, in 2006 TEP purchased a lease equity covering 14.1% undivided interest in Springerville Unit 1 for $48.03 million. The lease was amended to eliminate the equity portion of rent payments. According to Mr. Grant, TEP continued making rent payments to cover the principal and interest payments on lease obligation bonds. In January 2015, TEP took direct ownership of the 14.1% undivided interest when the bonds were paid in full.

Q. Is TEP proposing an adjustment in this case related to its 14.1% ownership interest?

A. Yes. TEP is proposing to include the original $48.03 million acquisition cost in rate base, with a reduction of $5.31 million to reflect previous rent reduction benefits covering 2007 and 2008 that have been retained by TEP. Thus, TEP's net requested rate base is $42.72 million.

Q. What adjustment has TEP made in this case to reflect this $42.72 million in rate base?

A. Since purchasing the 14.1% lease equity in 2006, TEP has been amortizing its purchase in its accounting records. As of December 31, 2014, TEP's remaining unamortized amount was $36.06 million when the $5.31 million rent benefits credit is included. The associated accumulated amortization as of this date was $6.65 million. In addition, to reflect the proper test year period, TEP includes $0.07 million for six months of additional accumulated depreciation to reflect the unamortized balance as of June 30, 2015. TEP's total adjustment reflects the sum of these two amounts, $6.65 million and $0.7 million, for a total adjustment of $6.73 million to obtain the net Total Company requested rate base of $42.72 million.

Q. Do you agree with TEP's proposed test year amount for its 14.1% lease equity interest?

A. No. TEP's requested amount does not constitute a reasonable ratemaking treatment. As an initial matter, TEP's request to introduce into rate base today an acquisition that was made in 2006 is highly unusual. Second, the requested valuation of this acquisition for rate base purposes in an amount that is very close to the purchase price ten years ago strikes me as questionable on its face, given that the asset has been depreciating. Third, this situation is further convoluted by the applicable lease provisions during the interim period, during which time customers have paid for use of this asset in TEP's revenue requirement. Finally, the requested rate base amount of $42.72 million for the 2006 purchase exceeds the net book value of this asset, which on June 30, 2015 was only $26.53 million.[31]

Q. In your opinion, what is the proper rate base amount to include for TEP's 2006 lease equity purchase?

A. In light of the considerations I noted above, it does not strike me as reasonable to include in rate base an amount in excess of this asset's net book value. Therefore, I recommend using the net book value of the asset as of June 30, 2015 to value the rate base addition associated with the 2006 acquisition. Based on the net book value of the total SGS 1 unit, this amount is $26.53 million. Therefore, I am recommending a $16.26 million (total company) adjustment. As shown in Exhibit KCH-5, this adjustment reduces TEP's revenue requirement by approximately **$1.488** million.

[31] TEP's Response to AECC Data Request 11.3, provided in Exhibit KCH-18. To derive the $26.53 million the total plant net book value as of June 30, 2015 provided in the data response was multiplied by 14.1%, the 2006 lease equity purchase percentage.

Legal Costs

Q. **What are your concerns regarding the amount of legal costs included in TEP's proposed revenue requirement?**

A. I have concerns regarding the amount of legal costs included in TEP's requested revenue requirement both with respect to legal expense and rate base.

Q. **What are your concerns regarding the inclusion of legal *expense* in TEP's proposed revenue requirement?**

A. The test period includes an exceptionally high level of legal expense. As shown in Exhibit KCH-7, page 3, the adjusted test period legal expense of $3.256 million is well in excess of $1.776 million average for the three-year period 2011 through 2013, prior to the test period. It appears that much of this increase is attributable to litigation between TEP and the 50.5% owner of Springerville Unit 1, Alterna.

Q. **How should the extraordinary level of legal expense associated with the Springerville Unit 1 litigation be treated for ratemaking purposes?**

A. The extraordinary level of legal expense associated with the Springerville Unit 1 litigation should be removed from the retail revenue requirement. There are two reasons for this. First, the nature of the litigation concerned a dispute between power plant owners. Retail customers should not be responsible for underwriting TEP's legal costs in such a dispute, which lies outside the purview of providing retail service. In this proceeding, TEP has gone to considerable lengths to differentiate between its ACC-jurisdictional activities and business activities that TEP does not consider to be ACC jurisdictional, such as the profits that TEP makes from providing services to the owners of Springerville Units 3 and 4. TEP's revenue requirement proposal insulates the majority of those profits from being shared with customers and used to offset a portion of the increase in retail revenue requirement the Company is requesting.[32] The same reasoning applies here, except that in this instance, TEP is incurring *costs* that are outside the purview of retail service. Consequently, it is not appropriate to include these costs in the retail revenue requirement.

The second reason for excluding these costs from recovery is their exceptional nature. The adjusted test year legal expenses exceed the average of the three-year period 2011 through 2013 by $1.480 million, largely due to Springerville Unit 1 litigation expense. As such, the Springerville Unit 1 litigation expense should not be considered to be representative of ongoing legal expenses and should be adjusted out of the retail revenue requirement on those grounds alone.

Q. What is your recommendation to the Commission regarding legal expense?

A. I recommend that the extraordinary level of legal expense associated with the Springerville Unit 1 litigation should be removed from the retail revenue requirement.

Q. What is your concern regarding legal costs that TEP proposes to include in *rate base*?

A. TEP is proposing to include $919,042 of legal costs associated with its Alterna litigation in rate base as part of the acquisition cost of Springerville Unit

[32] See direct testimony of Dallas J. Dukes, p. 50. TEP's Income – Springerville Units 3 and 4 workpaper shows $28.5 million in net income from services provided to Springerville Units 3 and 4, $8.3 million of which is credited to customers and $20.2 million of which is retained by TEP.

1.[33] Just as I argued above with respect to legal expense, the cost of litigating the disputes between TEP and Alterna should not be shouldered by customers, as the disputes between these two facility owners are outside the purview of providing retail service. Therefore, these costs should not be included in rate base. As I noted above, TEP is careful to differentiate business activities that the Company does not consider to be ACC-jurisdictional when the benefits accrue to the Company. The same principle should apply to costs.

Q. What is your recommendation to the Commission regarding the inclusion of legal costs in rate base?

A. I recommend that TEP's proposal to include in rate base certain legal costs associated with the Springerville Unit 1 litigation between TEP and Alterna should be rejected.

Q. What is the impact on TEP's jurisdictional revenue requirement from your recommendations regarding legal costs?

A. My adjustment to rate base is presented in Exhibit KCH-6. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.088** million relative to TEP's filed case.

My adjustment to legal expense is presented in Exhibit KCH-7. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.343** million relative to TEP's filed case.

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[33] Direct testimony of Kentton C. Grant, p. 33. Also, TEP Response to AECC Data Request 10.2.a.iv (provided in Confidential Exhibit KCH-19) as further clarified by TEP.

Payroll Expense

Q. What is TEP proposing regarding payroll expense?

A. Payroll expense is discussed in the Direct Testimony of TEP witness Frank P. Marino. Mr. Marino explains that TEP's Payroll Expense Adjustment was computed based on the average of O&M wages for the 12 month periods ended June 30, 2015 and June 30, 2014.[34] Using the average O&M wages for these two periods, TEP calculates an incremental two percent (2%) increase for 2016 and another two percent (2%) increase for 2017. The total incremental wage escalation is added to June 30, 2015 wages to arrive at TEP's adjusted payroll expense.[35]

Q. What is your assessment of TEP's proposal?

A I disagree with TEP's inclusion of a second 2% wage escalation for 2017. The test period in this case is the twelve month period ended June 30, 2015. While the merit of the 2% escalation adjustment for 2016 may be arguable in the context of an historical test period, which is nominally being used in this case, I am prepared to accept this portion of the adjustment as a known and measurable change. However, the second escalator for 2017 extends TEP's pro forma adjustment thirty months beyond the test period. I believe this is far too much of a stretch.

Q. What is your recommendation to the Commission regarding payroll expense?

[34] Direct Testimony of Frank P. Marino, p. 31.
[35] TEP's Income – Payroll Expense workpaper.

A. TEP's use of a second 2% payroll expense escalator for 2017 should be rejected. I present my adjustment to TEP's proposal in Exhibit KCH-8, which also includes a conforming adjustment to TEP's payroll tax expense adjustment. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.222** million relative to TEP's filed case.

Q. Do you have any other concerns regarding TEP's proposed escalation of labor-related costs?

A. Yes. My concerns regarding the escalation of short-term incentive compensation expense are discussed in below. Further, TEP intended to include escalation of 2% for 2016 and 2% for 2017 of its contribution to employees' 401(k) plan, and medical, dental, vision, life and long-term disability costs in the revenue requirement.[36] However, this adjustment was apparently inadvertently omitted from TEP's original Pension and Benefits adjustment. Consistent with my recommendation above regarding 2017 escalation of payroll expenses, I recommend that the Commission reject TEP's 2% escalation of benefits O&M expenses for 2017 because it is overreaching. Although TEP's benefits adjustment is not in its as-filed revenue requirement, the 2017 portion of TEP's adjustment, if adopted, would increase the Total Company revenue requirement by $312,700, and the ACC jurisdictional revenue requirement by approximately $262,380.[37] I recommend against including these increases in any correction to its filing that TEP may offer later in this proceeding.

[36] Direct Testimony of Frank P. Marino, p. 32.
[37] TEP's Income – Pension_Benefits Revised workpaper, provided in TEP's March 18, 2016 Supplemental Response to UDR 1.001.

Short-Term Incentive Compensation

Q. Please describe TEP's short-term incentive compensation plan.

A. All non-union employees are eligible for the short-term incentive plan, called the Performance Enhancement Plan ("PEP"). Short-term incentive compensation payouts are determined by specific PEP metrics. In the 2015 PEP, a Net Income goal received the greatest weighting, at 40 percent. A goal related to O&M Expense containment received a 20 percent weighting. Goals related to Equivalent Availability Factor, System Average Interruption Duration Index, Customer Satisfaction, and OSHA Recordables received a 10 percent weighting each. TEP reports that its 2014 PEP consisted of similar metrics and weightings.[38]

Q. What has TEP proposed with respect to short-term incentive compensation?

A. TEP is proposing to include 100 percent of the PEP expense in rates, based on the average PEP expense for the Test Year and the prior year ended June 30, 2014, including a 2% annual cost escalation assumption applied through 2017.[39]

Q. In your opinion, is it appropriate to recover the cost of short-term incentive plans in utility rates?

A. It can be appropriate to recover the cost of short-term incentive plans in utility rates to the extent that the compensation in such plans is not excessive, and to the extent the goals of such plans are not tied to utility financial performance, but rather to goals such as customer satisfaction, operating efficiency, and safety.

[38] Direct Testimony of Frank P. Marino, pp. 36-37.
[39] Direct Testimony of Frank P. Marino, pp. 37-38; TEP's Income – Short Term Incentive Compensation workpaper.

While rewarding employees for financial performance can be entirely appropriate, the responsibility for funding such awards rests most appropriately with shareholders, who are the primary beneficiaries of meeting or exceeding financial targets.

Q. What is your recommendation to the Commission regarding recovery of short-term incentive compensation expense?

A. I recommend that shareholders fund 40 percent of the short-term incentive compensation costs, based on the weighting of the 2015 PEP Net Income goal. Arguably, the O&M Expense goal also relates to financial performance, but I am limiting my adjustment to the Net Income goal portion at this time. Similarly to TEP, I calculated my adjustment based on average PEP expense for the Test Year and the prior year ended June 30, 2014. However, consistent with my Payroll Expense adjustment, I recommend that TEP's 2% escalation for 2017 be rejected. I present my adjustment to TEP's proposal in Exhibit KCH-9, which also includes a conforming adjustment to TEP's payroll tax expense adjustment. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.972** million relative to TEP's filed case.

Long-Term Incentive Compensation

Q. Please describe TEP's long-term incentive compensation program.

A. According to the Direct Testimony of Mr. Marino, the long-term incentive ("LTI") compensation program is designed to link a portion of executive officers' compensation to the achievement of multi-year financial results, and serve as a retention tool for executives. LTI awards consist of two components:

performance units and restricted stock units, each subject to a three-year vesting schedule.[40]

According to the 2015 LTI Term Sheet,[41] performance units comprise <BEGIN CONFIDENTIAL>[redacted] and restricted stock units comprise [redacted] of LTI awards. The goals associated with performance units are [redacted]<END CONFIDENTIAL>, the interests of stock awards recipients are naturally aligned with those of shareholders.

Fortis Inc., TEP's parent company, states the following in its *2015 Management Information Circular*, "Medium- and long-term incentives are granted to align executives' interests with those of Shareholders through increasing Shareholder value by fostering Common Share ownership and tying incentive compensation to the value of the Common Shares."[42]

Q. What is TEP proposing with respect to LTI compensation?

A. TEP is proposing to recover the cost of its LTI compensation program in rates, based on the average LTI expense for the Test Year and the prior year ended June 30, 2014.

Q. Did TEP request recovery of LTI compensation in its last general rate case?

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[40] Direct Testimony of Frank P. Marino, pp. 40-41.

[41] See TEP's Response to AECC Data Request 4.10, AECC 4.10- 2015 LTI Term Sheet- Confidential, provided in Confidential Exhibit KCH-19.

[42] Fortis Inc. *Notice of Annual Meeting and Management Information Circular* (20 March 2015), p. 48.

A. No. TEP did not request recovery of LTI compensation in its last two general rate cases.[43]

Q. What is your recommendation to the Commission regarding recovery of LTI expense?

A. I recommend that shareholders continue to fund the cost of TEP's LTI compensation program. As financial performance is the focus of the LTI program, the funding of such awards rests most appropriately with shareholders. I believe that continued exclusion of LTI expense from the revenue requirement is appropriate. I present my adjustment to TEP's proposal in Exhibit KCH-10. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.296** million relative to TEP's filed case.

Supplemental Executive Retirement Plan "SERP"

Q. What is a supplemental retirement plan?

A. A supplemental retirement plan, also known as a nonqualified retirement plan, or a "Top Hat Plan", is any plan that does not meet the requirements of Internal Revenue Code Sections 401-416 and therefore lacks the tax advantages conferred upon qualified pension plans. That is, it represents retirement contributions beyond what is included in standard corporate retirement plans. Typically, nonqualified plans are intended to benefit a select group of highly-compensated employees.

Q. Did TEP request recovery of SERP costs in its last general rate case?

A. No.

[43] See TEP's Response to RUCO Data Request 5.2, provided in Exhibit KCH-18.

Q. What is TEP proposing regarding SERP?

A. Unlike its last rate case, TEP is proposing to include the cost of SERP in rates. The SERP expense is included in TEP's Pension and Benefits adjustment.[44]

Q. Do you agree with TEP's proposal to include the cost of SERP in rates?

A. No, I do not. Restraint should be shown in asking customers to fund the extraordinary retirement benefits reflected in nonqualified retirement plans. The cost of these exceptional retirement benefits granted to a select group of highly-compensated employees is most appropriately borne by shareholders, not customers.

Q. What is your recommendation to the Commission regarding recovery of SERP expense?

A. I recommend that SERP expense continue to be excluded from the revenue requirement. I present my adjustment to TEP's proposal in Exhibit KCH-11. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.950** million relative to TEP's filed case.

Severance Expense

Q. What is TEP proposing with respect to severance expense?

A. TEP is requesting to recover severance pay of $365,688, of which $111,835 is capitalized and $253,853 is expensed. TEP justifies this recovery from ratepayers on the grounds that severance costs are incurred in the ordinary course of business.[45]

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[44] Direct Testimony of Frank P. Marino, pp. 32-33.
[45] See TEP Response to Staff Data Request 7.14, provided in Exhibit KCH-18.

Q. Do you agree that inclusion of severance expense in the revenue requirement is appropriate?

A. No. Severance expense should only be incurred if there is a net savings from the arrangement. In between rate cases the sole beneficiary of the cost savings from severance packages is the Company, so the Company has a financial incentive to offer cost-saving severance packages without recovery from customers in rates. Moreover, with respect to the ongoing nature of severance arrangements alleged by TEP, I note that TEP has not incorporated any net savings from future severance deals in its payroll expense. Therefore, it is not reasonable to include severance expense in the retail revenue requirement either.

Q. What is your recommendation to the Commission regarding recovery of severance costs?

A. I recommend that severance costs be excluded from the revenue requirement. I present my adjustment to TEP's proposal in Exhibit KCH-12. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.218** million relative to TEP's filed case.

Credit Card Processing Fees

Q. What is TEP proposing regarding credit card processing fees?

A. Currently, TEP customers making credit card payments are charged a fee of $3.50 per transaction, which recovers 100% of third-party fees for these transactions. TEP is requesting to reduce the fee charged to customers paying with credit cards to $1.00 per transaction, and charge the balance of the fees to the

Company, for inclusion in operating expenses to be paid by all customers.[46] Further, TEP projects that its reduced credit card fee policy will result in the credit card transaction volume increasing 70 percent over the next three years (2017-2019).[47]

TEP proposes to include in its revenue requirement the annual cost associated with the remaining $2.50 per transaction not borne by credit card paying customers, based on its projected average annual cost over the 2017 through 2019 period, including the escalating transaction volumes that TEP forecasts.

Q. Do you agree with TEP's proposal to change its credit card processing fee policy and pass the remaining costs onto all customers?

A. No, I do not. This problem illustrates one of the challenges in dealing with a regulated monopoly. TEP's current credit card processing fee policy may be an irritant to those customers wishing to pay by credit card, but it properly aligns the transaction cost incurrence with cost recovery. Most businesses avoid annoying their customers with such fees by absorbing the costs of these transactions into their bottom lines, but as a monopoly TEP seeks to transfer these costs to *all other customers* by increasing its requested base revenue requirement. I do not believe it is appropriate to shift the cost responsibility for these fees by reducing the fee charged to customers paying by credit card and then passing the remaining costs onto all customers. Moreover, TEP's proposal to recover a

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[46] Direct Testimony of Dallas J. Dukes, p. 58; Direct Testimony of Denise A. Smith, p. 5.
[47] See TEP's Response to RUCO Data Request 5.1, provided in Exhibit KCH-18; TEP's Income – Credit Card Processing Fees workpaper.

portion of the escalation in costs that the Company projects for these fees over the period 2017-2019 is overreaching and unreasonable.

Q. What is your recommendation to the Commission regarding credit card processing fees?

A. I recommend that the entirety of these fees continue to be paid directly by customers who choose to pay their bills with credit cards. I present my adjustment to TEP's proposal in Exhibit KCH-13. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$3.482** million relative to TEP's filed case.

Generation Overhaul Expense

Q. What has TEP proposed with respect to generation overhaul expense?

A. Generation overhauls occur over multi-year cycles. For this reason, the expense incurred in any one test period may not be reasonably representative of going-forward expense. To address this concern, it is appropriate to normalize generation overhaul expense using a representative time period.

TEP evaluates generation overhaul expense using both historical and projected data from 2008 through 2024 to determine the frequency of major and minor overhauls. TEP then uses this information to determine an average annual overhaul expense using its projected overhaul expenses for the 2016 to 2024 period. TEP uses the average annual projected overhaul expense as the adjusted test year value.

Q. Do you agree with TEP's approach?

A. No. I do not agree with TEP's use of projected expenses for the 2016 to 2024 period because it is far too speculative. Rather, it is preferable to normalize generation overhaul expense by using historical data over a multi-year period. An exception may be appropriate for *new* facilities for which historical overhaul information is not available.

Q. What is your recommendation to the Commission regarding generation overhaul expense?

A. I recommend that generation overhaul expense be normalized using the historical period, 2012-2015, with one year of actuals and three years of projections for the newly acquired Gila River plant and four years of projections for the newly-converted Sundt Unit 4 plant. This adjustment is presented in Exhibit KCH-14. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.865** million relative to TEP's filed case.

Return on Equity

Q. What return on equity is TEP proposing?

A. TEP is proposing a return on equity ("ROE") of 10.35%.[48] This return represents an increase of 35 basis points over the 10.00% ROE approved in Decision No. 73912, issued June 27, 2013, in Docket No. E-01933A-12-0291.

Q. Does AECC support TEP's request?

A. No. Please refer to Exhibit KCH-15, page 2, which shows the ROEs for vertically-integrated electric utilities approved in the United States from January 1, 2012 through December 31, 2012, as reported by SNL Financial. Page 3 of this

[48] See direct testimony of Ann E. Buckley, p. 5.

exhibit shows the ROEs for vertically-integrated electric utilities approved in the country from January 1, 2015 through March 31, 2016, also as reported by SNL Financial.

The median ROE for this group was 10.20% in 2012, the year in which the last TEP rate case was conducted.[49] The 10.00% ROE that TEP was awarded in the last general rate case was 20 basis points below that median. Authorized ROEs in the electric utility industry have fallen since that time. In the 15 months from January 1, 2015 through March 31, 2016, the median approved ROE for vertically-integrated electric utilities was 9.71%. Thus, TEP's proposed ROE of 10.35% is moving in exactly the opposite direction of the trend nationally. If TEP's ROE were to be reset at a rate reflective of the national median, it would be in the vicinity of 9.70%.

Q. **If TEP's allowed ROE were to be set at the national median of approximately 9.70%, how would TEP's effective return be impacted by the fair value increment?**

A. Unlike the vast majority of utilities in the country, the fair value increment provides Arizona utilities with a premium return above the nominal ROE applied to original cost rate base. Thus, even if TEP's nominal ROE were to remain in line with the national median, TEP's effective ROE would actually be somewhat higher, due to the fair value increment.

[49] TEP filed its Application in that case on July 2, 2012 and the Stipulation in that case was filed on February 4, 2013.

Q. **In offering the preceding discussion of national trends, are you intending to supplant the Commission's consideration of traditional cost-of-capital analysis?**

A. No. I fully expect that Staff, and perhaps RUCO, will file cost-of-capital analyses for the Commission's consideration, along with that filed by TEP. My discussion of national trends is intended to supplement that analysis.

Q. **What would be the revenue requirement impact if TEP's ROE were set at 9.70%?**

A. The revenue requirement impact of setting TEP's allowed ROE equal to 9.70% is presented in Exhibit KCH-15, page 1. It reduces TEP's ACC jurisdictional revenue requirement by approximately **$10.826 million** relative to TEP's filed case. I have incorporated an ROE of 9.70% into AECC's overall revenue requirement recommendations at this time, pending further information being presented into the record by other parties.

Jurisdictional Demand Allocation

Q. **What is the role of jurisdictional demand allocation in determining the retail revenue requirement in this case?**

A. An initial step in determining the retail revenue requirement is the allocation of costs between the retail jurisdiction and the wholesale jurisdiction. This is necessary because a portion of TEP's production plant is devoted to providing long-term sales to wholesale customers. The profits from these sales are retained by TEP and are not credited to retail customers; therefore, it is important that these costs be properly allocated to the wholesale jurisdiction. The allocation of jurisdictional demand is the process by which the share of production fixed costs allocated to the wholesale jurisdiction is determined.

Q. What has TEP proposed in this case regarding jurisdictional demand allocation?

A. TEP has proposed to allocate of 4.34% of its production demand costs to the wholesale jurisdiction. The allocation to the wholesale jurisdiction is intended to capture test period long-term sales commitments to Navajo Tribal Utility Authority, Tohono O'odham Utility Authority, and Trico. However, TEP has made adjustments to exclude from the jurisdictional demand allocation two large long-term sales contracts, Salt River Project ("SRP") and Shell Energy North America ("Shell Energy").[50]

Q. What is TEP's justification for excluding these two long-term sales contracts from the jurisdictional demand allocation?

A. TEP proposes to exclude the SRP contract as a post-test-period adjustment because it expires in May 31, 2016. Similarly, TEP proposes to exclude the Shell Energy contract also as a post-test-period adjustment because it expires December 31, 2017.[51]

Q. How are these two contracts treated for ratemaking purposes today?

A. The SRP contract was assigned <BEGIN CONFIDENTIAL> [redacted] <END CONFIDENTIAL> MW of jurisdictional demand in the last general rate case.[52]

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[50] TEP's Response to Staff Data Request 3.3, STF 3.3 Jurisdictional Allocation-Confidential, provided in Confidential Exhibit KCH-19.
[51] Direct testimony of Michael E. Sheehan, p. 41; TEP's Response to AECC Data Request 7.5, provided in Exhibit KCH-18.
[52] Docket No. E-01933A-12-0291, TEP's 2011 Jurisdictional Allocation 12-31-11 workpaper.

The Shell Energy contract was not signed until December 12, 2014;[53] therefore, it was not included in the jurisdictional demand allocator in that case.

Q. Who is receiving the profits from the Shell Energy sales contract?

A. Currently, all profits from the Shell Energy sales contract accrue 100% to TEP and its shareholders. No benefits accrue to customers.

Q. How is this ratemaking treatment reasonable, considering that the Shell Energy contract was not included in the jurisdictional demand allocation?

A. On a standalone basis this arrangement is <u>not</u> reasonable, given that the Shell Energy sales occur from assets that are paid for by retail customers, without any costs allocated to this contract. However, the settlement agreement negotiated in the last general rate ("2013 Settlement Agreement") included as part of the package a provision that altered TEP's PPFAC Plan of Administration ("POA") to exclude all margins from new long-term sales contracts from the revenues credited to customers in the PPFAC.[54] As a result of this change to the POA, the benefits from the Shell Energy contract accrue solely to TEP and its shareholders. I propose to reverse this change going forward, but I will address this issue separately in my testimony.

Q. Does TEP propose to recognize margins from the Shell Energy contract in the PPFAC going forward?

A. Yes. In combination with excluding the Shell Energy contract from the jurisdictional demand allocation, TEP is proposing to recognize $2.7 million in

[53] Direct testimony of Michael E. Sheehan, p. 41.
[54] Docket No. E-01933A-12-0291, February 4, 2013 Settlement Agreement, paragraph 6.2; Attachment C.

projected margins from this contract in 2017 base fuel and purchased power costs.[55]

Q. What is your assessment of TEP's proposed jurisdictional demand allocation in this case?

A. I do not object to TEP's adjustment to remove the SRP contract, even though it was in effect during the test period, because the contract ends within twelve months of the conclusion of the test period and there appears to be little likelihood that it will be renewed. However, I recommend against TEP's exclusion of the Shell Energy contract from the jurisdictional demand allocation. Not only was this contract in effect during the test period, it will remain in effect until the end of 2017 – two and a half years beyond the end of the test period. Moreover, per the terms of the change in the POA discussed above, TEP will be the sole beneficiary of the margins from this contract until 2017, when TEP proposes to apply the exception to the adopted PPFAC treatment (discussed above) that would recognize the margins from this contract in base fuel and purchased power costs.

In my view, the expiration date of the contract is too far forward to justify exclusion from a test period ending June 30, 2015. Between now and the expiration date, the contract could be extended or replaced with a new long-term contract to another party which also would not be included in the jurisdictional demand allocation – and the profits from any such replacement contract would flow exclusively to TEP per the current terms of the POA. Moreover, having successfully changed the PPFAC treatment of margins from new long-term

[55] Direct testimony of Michael E. Sheehan, p. 41.

contracts, such as the Shell Energy contract, to its advantage, TEP's proposal to now exclude the Shell Energy contract from the jurisdictional demand allocation strikes me as "cherry-picking," which is unreasonable and should be denied.

Q. What is your recommendation regarding jurisdictional demand allocation?

A. TEP's proposal to adjust the jurisdictional demand allocation to remove the Shell Energy contract should be rejected. I have prepared an adjustment that recalculates the jurisdictional demand allocation factor after assigning the demand associated with this long-term contract to the non-ACC jurisdiction. My adjustment also reverses the $2.7 million credit to customers proposed by TEP for 2017 base fuel and purchased power costs.

Q. What is the revenue requirement impact of adopting your jurisdictional demand allocation adjustment?

A. The revenue requirement impact from my adjustment is presented in Exhibit KCH-16. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$14.043** million relative to TEP's filed case, inclusive of the reversal of the $2.7 million credit to customers proposed by TEP for 2017 base fuel and purchased power costs.

Headquarters Building

Q. What has TEP proposed with respect to recovery of the costs of its headquarters building?

A. TEP has spent approximately $98.7 million related to construction of, and upgrades to, a relatively new headquarters building constructed in downtown

Tucson in 2011.[56] TEP is proposing to include the cost of the headquarters building in rate base, where it would earn a return at the Company's weighted average cost of capital. TEP would also recover the depreciation expense and ongoing operations expense in its proposed revenue requirement.

Q. How is the headquarters building treated in current rates?

A. In the last general rate case, in addition to recovery of expenses, TEP proposed to include the headquarters building in rate base where it would earn a return at the Company's weighted average cost of capital. On behalf of AECC, I objected to that treatment and recommended instead that TEP be allowed to recover its costs, but that the return on its capital invested in the new headquarters building should be limited to the cost of long-term debt. My proposal to limit the return on the headquarters building to the cost of debt was incorporated into the 2013 Settlement Agreement in that case which was approved by the Commission.

Q. Do you agree with TEP's proposal to change the recovery of costs associated with its headquarters to reflect a return at the weighted average cost of capital?

A. No, I do not. While corporate facilities are obviously necessary to conduct business, TEP had corporate facilities prior to the construction of the new facility, albeit less desirable. I believe it is reasonable to ask whether significant outlays on new corporate headquarters constitute the type of "investment" that utilities should be incented to make on par, say, with investments in distribution, generation, and transmission that provide direct benefits or service to customers. In TEP's case, customers are being asked to provide the Company with an equity

[56] TEP Response to AECC Data Request 15.1, AECC 15.1 Support, provided in Exhibit KCH-18.

return on an expensive building[57] that will not provide or deliver a single kilowatt-hour to customers. It is fair to ask whether this type of growth in rate base should be encouraged and rewarded.

In my opinion, it is not reasonable for TEP customers to pay the Company a return on these discretionary expenditures that is comparable to the return on investment in an asset that is more necessary to the provision of electric service. Rather, just as in the last rate case, I propose that TEP be allowed to recover its costs and a return on its capital invested in the new headquarters building, but not at the level of return allowed for its other assets in rate base. Instead, recovery of the headquarters expenditures – plus a carrying charge equal to the cost of long-term debt – is a more appropriate cost recovery treatment. I believe this is a proportionate approach that would fully reimburse the Company for its costs plus a reasonable cost of capital without unjustly enriching the Company for having made this expensive discretionary expenditure.

Q. What is the revenue requirement impact of adopting your proposed ratemaking treatment for the new headquarters building?

A. The revenue requirement impact of limiting TEP's return to the cost of long-term debt for its headquarters building is presented in Exhibit KCH-17. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$3.552 million** relative to TEP's filed case.

[57] As Staff witness Ralph C. Smith pointed out in TEP's last general rate case, the per-employee cost of the new headquarters was 77% higher than the per-employee cost of TEP's previous headquarters. Docket No. E-01993A-12-0291. Direct Testimony of Ralph C. Smith, p. 24.

PPFAC REVENUE-RELATED ISSUES

Q. What PPFAC revenue-related issues are you addressing?

A. I am addressing two revenue-related issues: (1) the lack of a risk-sharing mechanism in the PPFAC, and (2) the treatment of margins from new long-term contracts.

Q. What is your general view regarding a risk-sharing mechanism in the PPFAC?

A. Although a risk-sharing provision is lacking in the current PPFAC, I am recommending in this case that the Commission approve such a sharing mechanism.

Q. Why do you believe a risk-sharing mechanism is an important feature of a fuel adjustor?

A. A risk-sharing mechanism is essential to keep customer and Company interests aligned. Under the current PPFAC, TEP simply passes through 100% of changes in base fuel and purchased power costs in between rate cases to customers. This type of 100 percent cost pass-through seriously reduces a utility's incentive to manage its fuel and purchased power costs as well as it would manage them if it remained exposed to the energy cost risk. It is axiomatic that when a firm stands to gain or lose from its cost management decisions, the pursuit of its economic self-interest gives it a powerful incentive to perform well in managing its costs. I strongly recommend against continuing with a PPFAC design that fails to incorporate this natural economic incentive.

Q. But aren't energy costs largely outside a utility's control?

A. Absolutely not. The utility's energy costs are completely out of the customers' control, but not of the utility. Utilities are not mere passive bystanders when it comes to managing power costs. Every hour of every day, utilities need to be managing the dispatch of their systems to achieve minimum costs, subject to the reliability constraints under which they operate. This requires a sophisticated approach to managing utility-owned resources, as well as conducting a large volume of transactions – purchases and sales – throughout the year. The depth and breadth of this around-the-clock dispatch and balancing requirement is so extensive that it is inadvisable for regulators to rely solely on after-the-fact prudence audits to ensure sound utility cost-management performance; rather it is far preferable for the Commission to harness the natural economic self-interest of the company to incentivize the desired behavior of ensuring sound utility cost-management performance.

Q. Are there other aspects of managing fuel and purchased power costs that are important besides optimizing system dispatch?

A. Yes. In addition to hourly dispatch, TEP enters into numerous transactions throughout the course of the year that impact its fuel and purchased power costs, such as short- and long-term purchases and sales and fuel procurement. For example, TEP transacted for nearly 3.5 billion kilowatt-hours short-term power purchases in 2015, valued at over $102 million, consummated with more than 50 counterparties. The Company also made more than 4.5 billion kilowatt-hours of short-term sales in 2015, worth more than $129 million, transacted with more than 40 counterparties.[58] It is critical that TEP have the proper incentives for these transactions to produce the greatest possible net benefit to customers. This incentive is most efficiently implemented by a regime in which TEP shares in the benefits and risks of its decisions.

Q. How else do incentives play a role?

A. Incentives also play an important role with respect to the Company's own operations. For example, it is important for TEP to schedule plant maintenance in a manner that takes into account the impact on power costs. By scheduling outages when replacement power is likely to be less or least expensive, the Company is able to control its power costs. A sharing mechanism gives the Company an economic incentive to take proper account of power costs when scheduling outages. Further, under a sharing mechanism, if the Company experiences forced outages that are more frequent or of greater duration than is reasonably projected in rates, the Company shares in the economic consequences of these events. Likewise, if forced outages are less frequent than had been reasonably projected, the Company shares in the benefit of such superior performance. None of this occurs with a 100% pass-through to customers.

Q. Does TEP hedge a portion of its fuel and purchased power costs?

A. Yes. When a utility hedges its fuel and/or purchased power costs, it is effectively locking in the cost of fuel and/or purchased power that is expected to be consumed in the future. <BEGIN CONFIDENTIAL>[redacted]

[58] Source: TEP 2015 FERC Form 1, pp. 310-11; 326-27.

[redacted][59]<END CONFIDENTIAL>

So while it is correct that utilities do not control the market price of natural gas, for example, it is nevertheless the case that a utility's *decisions* in executing its natural gas hedging strategy (e.g., timing, magnitude) have a large influence on the cost of gas that it ultimately incurs and the fuel costs that are passed on to customers.

Q. If TEP locks in forward fuel prices at prices that later decline, how are these costs treated for ratemaking purposes?

A. In a general rate case, under the current operation of the PPFAC, if the hedged price exceeds the projected market price, the difference is included as a component of fuel cost for full recovery from customers, subject only to prudency considerations. Conversely, if the hedged price is below the projected market price, this difference is credited against the fuel cost recovered from customers. In between rate cases, these differences are included in the PPFAC, and passed through 100 percent to customers.

Q. How does your proposal to introduce risk sharing in the PPFAC affect the sharing of risks related to TEP's hedging decisions?

A. Under the current arrangement, there is no risk whatsoever to TEP from its hedging decisions: short of a prudency disallowance, 100 percent of the risk from TEP's hedging decisions is borne by customers.

Under my proposal, if TEP's hedges turn out to cost more than was projected at the time of the general rate case, the Company shares in this cost;

[59] Source: Confidential TEP Response to UDR 1.098.

similarly, if the Company's hedging decisions prove to reduce fuel costs below what was projected in the general rate case, TEP shares in this gain.

Q. Do you believe that the threat of a prudency disallowance is sufficient incentive to fully align utility and customer interests in managing fuel costs in between rate cases?

A. No. In my view, the threat of a finding of imprudence following an after-the-fact audit is not a good substitute for a utility having "skin in the game" when it comes to managing its fuel costs. A finding of imprudence essentially requires a determination that a utility acted unreasonably in its power cost management. In contrast, a risk-sharing mechanism structured such that each and every transaction affects the Company's bottom line, provides an incentive for the Company to get the *best possible deal* from every transaction. Striving to get the best possible deal from every transaction is different from simply not behaving unreasonably. Getting the best possible deal is a more exacting and efficient aspiration. A well-crafted sharing mechanism supports this objective.

Q. Do other utility commissions in the Western United States require a sharing mechanism as part of power supply adjustors?

A. Yes. Oregon, Washington, Idaho, Montana and Wyoming have each adopted sharing mechanisms that apply to electric utility power cost adjustors approved in those states.

Q. Please describe the sharing mechanisms used in these other states.

A. In Oregon, the power cost adjustors of both Pacific Power and Portland General Electric are subject to an asymmetrical dead band ranging from negative $15 million to positive $30 million on Oregon jurisdictional basis. The utility absorbs or retains power cost variances within the dead band. Outside the dead band, a 90/10 sharing mechanism applies, with customers absorbing 90% of incremental costs above the dead band and receiving 90% of the benefits below the dead band. Further, recovery through the power cost adjustors is subject to an earnings test, with zero recovery or refund if the utility's actual ROE is within 100 basis points of its authorized level.[60]

In Pacific Power's Washington jurisdiction, the power cost adjustor is subject to a $4 million dead band. Asymmetrical sharing bands apply for net power cost variances between $4 million and $10 million, with 50/50 sharing applying to positive variances (net power cost under-recovery) and 75% customer/25% utility sharing applying to negative variances (net power cost over-recovery). Net power cost variances exceeding $10 million are subject to a symmetrical 90% customer/10% utility sharing provision.[61]

The latest version of Puget Sound Energy's power cost adjustor in Washington, effective January 1, 2017, includes a $17 million dead band. For variances between $17 million and $40 million, 50/50 sharing applies to positive variances and 65% customer/35% utility sharing applies to negative variances. For variances exceeding $40 million, 90% customer/10% utility sharing applies.[62]

Rocky Mountain Power's Idaho power cost adjustor contains a 90% customer/10% utility sharing mechanism for most components[63], and Montana-

[60] Pacific Power's Oregon power cost adjustment mechanism was adopted in OR Docket No. UE-246, Order No. 12-493 (December 20, 2012). Portland General Electric's power cost adjustment mechanism was adopted in OR Docket Nos. UE-180/UE-181/UE-184, Order No. 07-015 (January 12, 2007). The current mechanism is described in Portland General Electric's Schedule 126.
[61] WA Dockets UE-140762, *et al.*, Order 09 (May 26, 2015).
[62] WA Dockets UE-130617, *et al.*, Order 11 (August 7, 2015), Attachment A to Settlement Stipulation.
[63] ID Case No. PAC-E-15-09, Order 33440 (December 23, 2015).

Dakota Utilities Co.'s power cost adjustor in Montana also contains a 90/10 sharing mechanism.[64]

A 70% customer/30% utility sharing provision was adopted for Rocky Mountain Power's Wyoming power cost adjustor in 2011.[65] In its most recent Wyoming general rate case, Rocky Mountain Power proposed to replace the 70/30 sharing provision with a 100% pass-through to customers. However, the Wyoming commission rejected Rocky Mountain Power's proposal, retaining the 70/30 sharing provision in order to incent the utility to improve its base net power cost forecasts and control net power costs.[66]

Q. In your opinion, does the 70/30 sharing arrangement ordered by the Wyoming commission strike a reasonable balance between utility and customer interests?

A. Yes, it does. This sharing ratio places the substantial majority of responsibility for recovering base fuel cost deviations on customers, but it meaningfully aligns utility and customer interests through shared benefits and costs.

Q. Should this Commission consider adopting the 70/30 sharing provision as utilized in Wyoming?

A. Yes. I encourage the Commission to consider adopting the 70/30 sharing provision that was approved in Wyoming, rather than retaining the current 100/0 approach.

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[64] Montana-Dakota Utilities Co.'s Fuel and Purchased Power Cost Tracking Adjustment – Rate 58.
[65] WY Docket No. 20000-368-EA-10, Memorandum Opinion, Findings and Order (February 4, 2011).
[66] WY Docket No. 20000-469-ER-15, Memorandum Opinion, Findings of Fact, Decision and Order (December 30, 2015), p. 32.

Q. Turning to the second PPFAC-related topic you are addressing, what is your general view concerning the treatment of margins from long-term contracts in a fuel adjustor?

A. If a long-term sales contract is not assigned fixed production cost responsibility in the determination of inter-jurisdictional demand allocation, then the margins from those sales should be credited to customers in the same proportion as any sharing mechanism generally applicable to the fuel adjustor. So, for example, under the current PPFAC, which has no sharing mechanism, 100% of the margins from new long-term contracts that go into effect in between rate cases properly should be credited to customers, because such new long-term contracts would not be allocated any demand costs in the preceding general rate case. By the same token, if a 70/30 PPFAC sharing mechanism is adopted, then 70% of the margins should be credited to customers, consistent with the split of the overall sharing mechanism.

Q. What has been the recent history regarding the treatment of margins from long-term contracts?

A. Prior to the last general rate case, the margins from all wholesale transactions, irrespective of the duration of the contract, were credited to customers in the PPFAC, except for the margins from those long-term contracts that were used in the calculation of the jurisdictional demand allocation. The exclusion of these latter margins made sense because those long-term contracts were allocated a share of system production demand costs.

But in the last general rate case, TEP proposed to change the POA in a way that assigned 100% of the margins from new contracts longer than one year to the benefit of shareholders rather than customers. On behalf of AECC, I strongly opposed this change. However, this provision was included in the 2013 Settlement Agreement approved by the Commission in that case, which AECC supported as a package.

Q. What is your recommendation to the Commission regarding the treatment of margins from long-term contracts in this proceeding?

A. With the filing of this general rate case, this issue should be re-examined. In general, all revenues from wholesale sales, irrespective of term, should be credited against fuel and purchased power costs and included in the PPFAC, unless such sales are allocated a share of system costs. Consequently, the change in the POA approved in the last general rate case that shifted all the benefits from new long-term contracts from customers to shareholders should be reversed.

The generating resources that are used to make these sales are paid for by TEP customers. Consequently, in between rate cases, 100% of the margins from new long-term sales should be included in the PPFAC. If my proposal for risk sharing is adopted, 70% of the margins from new long-term sales (in between rate cases) should be credited to customers in the PPFAC and 30% to TEP. If my proposal for risk sharing is not adopted, then 100% of the margins should be credited to customers in the PPFAC.

ENVIRONMENTAL COMPLIANCE ADJUSTOR

Q. What is the Environmental Cost Adjustor ("ECA")?

A. The ECA allows recovery, with a cap, of government-mandated environmental compliance costs. Specifically, it allows TEP to pass through to customers in between rate cases the incremental costs of its qualifying environmental compliance investments, including return on investment, depreciation expense, taxes and associated O&M cost. The ECA was initiated pursuant to the 2013 Settlement Agreement approved in the last general rate case. The cap is set at 0.25% of TEP's total retail revenue.

Q. What has TEP proposed with respect to the ECA in this case?

A. TEP is proposing to double the cap to 0.50% of retail revenue. According to TEP witness Craig A. Jones, this change would increase revenues recovered through the ECA from $2 million to $4 million per year.[67]

Q. Do you agree with TEP's proposed doubling of the cap?

A. No. The ECA was included in the 2013 Settlement Agreement as a compromise. Many parties, including AECC, opposed the adoption of the ECA in the first instance, but a significant consideration in allowing the ECA to be included in the 2013 Settlement Agreement was the negotiated cap and its agreed-upon magnitude. I recommend against continuation of the ECA unless the specific cap of 0.25% of TEP's total retail revenue is retained. Otherwise, the ECA is an example of unwarranted single-issue ratemaking.

Q. What is single-issue ratemaking?

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in cost or revenue items considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

[67] Direct testimony of Craig A. Jones, p. 81.

When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just certain factors in isolation. Considering some costs or revenues in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. For example, the proposed ECA would allow TEP to earn a return on its new investment and charge customers for depreciation expenses associated with that new investment without recognizing that its existing rate base would have depreciated to a lower value at the time the ECA is charged to customers. In my opinion, the proposed ECA is a classic example of an application of single-issue ratemaking that is not in the public interest. I recommend that the ECA be terminated unless it is capped at the previously-negotiated 0.25% of TEP's total retail revenue.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT KCH-1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

As Adjusted by AECC

		ACC Jurisdiction					
Line No.	Description	Original Cost		RCND		Fair Value (FV)	
1	Adjusted Rate Base	$1,989,942	(a)&(b)	$3,549,687	(a)&(b)	$2,769,815	
2	Adjusted Operating Income	110,844	(c)	$110,844	(c)	$110,844	
3	Current Rate of Return (Ln. 2 ÷ Ln. 1)	5.57%		3.12%		4.00%	
4	Required Operating Income on OCRB @ WACC	$139,527		$139,527		$139,527	
5	Required Return on FV Increment	$12,166		$12,166		$12,166	
6	Required Operating Income	$150,601		$150,601		$150,601	
7	Weighted Average Cost of Capital	7.01%	(d)	7.01%		7.01%	
8	Fair Value Adjustment	0.56%		-2.77%		-1.57%	
9	Required Rate of Return (Ln. 6 ÷ Ln. 1)	7.57%	(d)	4.24%		5.44%	
10	Operating Income Deficiency (Ln. 6 - Ln. 2)	$39,757		$39,757		$39,757	
11	Gross Revenue Conversion Factor	1.6223	(e)	1.6223	(e)	1.6223	(e)
12	Increase in Gross Revenue Requirement (Ln. 10 x Ln. 11)	$64,499		$64,499		$64,499	
13	AECC Recommended Return on Headquarters Adjustment	($3,552)	(f)	($3,552)		($3,552)	
14	Net Increase in Gross Revenue Requirement (Ln. 12 + Ln. 13 + Ln. 14)	$60,947		$60,947		$60,947	
15	Adjusted Present Retail Revenues	$909,303	(g)	$909,303		$909,303	
16	Percent Change from Present Revs. (Ln. 15 ÷ Ln. 16)	6.70%		6.70%		6.70%	
17	TEP Claimed Revenue Deficiency	$109,534		$109,534		$109,534	
18	TEP Percent Change from Present Revs. (Ln. 18 ÷ Ln. 16)	12.05%		12.05%		12.05%	
19	AECC Change from TEP Claimed Revenue Deficiency (Ln. 15 - Ln. 18)	($48,587)		($48,587)		($48,587)	
20	AECC Percent Change from TEP Claimed Revenue Deficiency (Ln. 17 - Ln. 19)	-5.34%		-5.34%		-5.34%	

Supporting Schedules/Exhibits
(a) TEP Schedule B-1
(b) AECC Exhibit KCH-1, p. 7
(c) AECC Exhibit KCH-1, p. 4
(d) TEP Schedule D-1
(e) TEP Schedule C-3
(f) AECC Exhibit KCH-17, p. 1
(g) TEP Schedule C-3

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

As Filed by TEP

Line No.	Description	ACC Jurisdiction Original Cost (OCRB)		RCND		Fair Value (FV)	
1	Adjusted Rate Base	$2,104,678	(a)	$3,721,880	(a)	$2,913,279	
2	Adjusted Operating Income	$98,381	(b)	$98,381	(b)	$98,381	
3	Current Rate of Return (Ln. 2 ÷ Ln. 1)	4.67%		2.64%		3.38%	
4	Required Operating Income on OCRB @ WACC	$154,416		$154,416		$154,416	
5	Required Return on FV Increment	$11,482		$11,482		$11,482	
6	Required Operating Income	$165,898		$165,898		$165,898	
7	Weighted Average Cost of Capital (WACC)	7.34%	(c)	7.34%		7.34%	
8	Fair Value Adjustment	0.54%		-2.88%		-1.64%	
9	Required Rate of Return (Ln. 6 ÷ Ln. 1)	7.88%	(c)	4.46%		5.69%	
10	Operating Income Deficiency (Ln. 6 - Ln. 2)	$67,517		$67,517		$67,517	
11	Gross Revenue Conversion Factor	1.6223	(d)	1.6223	(d)	1.6223	(d)
12	Increase in Gross Revenue Requirement (Ln. 10 x Ln. 11)	$109,534		$109,534		$109,534	
13	Adjusted Present Retail Revenues	$909,325	(e)	$909,325		$909,325	
14	Percent Change from Present Revs. (Ln. 12 ÷ Ln. 13)	12.05%		12.05%		12.05%	

Supporting Schedules
(a) TEP Schedule B-1
(b) TEP Schedule C-1
(c) TEP Schedule D-1
(d) TEP Schedule C-3
(e) TEP Schedule H-1

Summary of AECC Proposed Cost of Capital
Test Year Ended June 30, 2015
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Cost of Capital
	AECC Proposed	(a)				
1	Short-Term Debt		N/A	N/A	N/A	N/A
2	Long-Term Debt - Net		1,441,656	49.97%	4.32%	2.16%
3	Common Stock Equity		1,443,610	50.03%	9.70%	4.85%
4	Total Capital		$2,885,266	100.00%		7.01%
	TEP Proposed - End of Test Period	(b)				
5	Short-Term Debt		$0	0.00%	0.00%	0.00%
6	Long-Term Debt - Net		$1,441,656	49.97%	4.32%	2.16%
7	Common Stock Equity		1,443,610	50.03%	10.35%	5.18%
8	Total Capital		$2,885,266	100.00%		7.34%

Supporting Schedules/Exhibits
(a) AECC Exhibits KCH-15
(b) TEP Schedule D-1, p. 1 of 2

Summary of AECC Revenue Requirement Adjustments

Operating Revenues and Expenses

Test Year Ended June 30, 2015
(Thousands of Dollars)

		TEP Total Company (a)			AECC Total Company (b)		TEP ACC Jurisdictional (a)			AECC ACC Jurisdictional (b)	
Line No.	Description	Unadjusted	Pro Forma Adjustments	Total Adjusted	Pro Forma Adjustments	Total Adjusted	ACC Jurisdiction Unadjusted	Pro Forma Adjustments	ACC Jurisdiction Adjusted	Pro Forma Adjustments	ACC Jurisdiction Adjusted
1	Operating Revenues										
2	Electric Retail Revenues	606,322	($944)	$605,378	($2,702)	$602,676	$606,322	($944)	605,378	($2,702)	$602,676
3	PPFAC Revenue	325,588	($21,663)	303,925	2,702	306,626	$325,588	($21,663)	303,925	2,702	306,626
4	Sales for Resale	162,821	(162,821)	(0)	0	(0)	0	0	0	0	0
5	Other Operating Revenue	223,661	($172,841)	50,820	0	50,820	204,570	(172,841)	31,729	0	31,729
6	Total Operating Revenues	1,318,392	(358,269)	960,122	(0)	960,122	1,136,480	(195,448)	941,031	0	941,031
7	Operating Expenses										
8	Fuel Expense	292,405	11,521	303,926	2,702	$306,627	244,771	59,155	303,926	2,702	306,627
9	Purchased Power - Demand	1,406	(1,405)	0	0	0	0	0	0	0	0
10	Purchased Power - Energy	192,561	(192,561)	(0)	0	(0)	0	(0)	(0)	0	(0)
11	Transmission	6,205	(6,205)	0	0	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	492,596	(188,671)	303,926	2,702	306,627	244,771	59,155	303,926	2,702	306,627
13	Other Operations and Maintenance Expense	417,887	(136,826)	281,061	(13,793)	267,268	366,742	(31,811)	334,931	(16,985)	317,946
14	Depreciation	143,586	13,306	156,891	(2,389)	154,503	118,030	11,673	129,703	(6,392)	123,310
15	Taxes Other than Income Taxes	50,111	3,205	53,315	(324)	52,992	39,180	1,555	40,735	(1,020)	39,715
16	Income Taxes	60,050	(19,574)	40,476	0	40,476	49,486	(16,130)	33,356	9,232	42,588
17	Total Operating Expenses	1,164,231	(328,560)	835,670	(13,804)	821,866	818,209	24,442	842,650	(12,463)	830,187
18	Operating Income	154,161	($29,709)	$124,452	$13,804	$138,256	318,271	(219,890)	$98,381	$12,463	$110,844
19	Other Income and Deductions										
20	Allowance for Equity Funds	4,572									
21	Other - Net	3,022									
22	Total Other Income and Deductions	7,594									
23	Income Before Interest Expense	161,755									
24	Interest Expense										
25	Interest on Long-Term Debt	56,729									
26	Interest on Short-Term Debt	909									
27	Other Interest Expense	4,497									
28	Allowance for Borrowed Funds	(2,922)									
29	Total Interest Expense	59,213									
30	Income Before Cumulative Effect of Accounting Change	102,542									
31	Cumulative Effect of Accounting Change - Net of Tax	0									
32	Net Income Available for Common Stock	$102,542									

Supporting Schedules/Exhibits/Data Source
(a) TEP Schedule C-1 and TEP Rev. Req't Model
(b) AECC Exhibit KCH-1, p. 7

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

Line No.		Bonus Tax Depreciation Expense ADIT Adjustment		Sundt & San Juan 2 M&S Regulatory Asset Adjustment		50.5% Co-Ownership of SGS 1 Regulatory Asset Adjustment	
		Total Company (a)	ACC Jurisdictional (b)	Total Company (c)	ACC Jurisdictional (d)	Total Company (e)	ACC Jurisdictional (f)
1	Operating Revenues						
2	Electric Retail Revenues	0	0	0	0	0	0
3	PPFAC Revenue	0	0	0	0	0	0
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	0	0	0	0	0
7	Operating Expenses						
8	Fuel Expense	0	0	0	0	0	0
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	0	0	0	0	0	0
13	Other Operations & Maintenance Expense	0	0	0	0	0	0
14	Depreciation and Amortization	0	0	0	0	(2,389)	(2,145)
15	Taxes Other than Income	0	0	0	0	0	0
16	Income Taxes	0	106	0	3	0	1,016
17	Total Operating Expenses	0	106	0	3	(2,389)	(1,128)
18	Operating Income	0	(106)	0	(3)	2,389	1,128
19	Rate Base - Original Cost	(15,887)	(12,814)	(409)	(409)	(23,887)	(23,887)
20	Rate Base - RCND	(34,299)	(27,664)	(409)	(409)	(23,887)	(23,887)

Line No.		Springerville Unit 1 2006 Lease Acquisition Adjustment		Springerville Unit 1 Capitalized Legal Expense Adjustment		Springerville Unit 1 Legal Expense Adjustment	
		Total Company (g)	ACC Jurisdictional (h)	Total Company (i)	ACC Jurisdictional (j)	Total Company (k)	ACC Jurisdictional (l)
1	Operating Revenues						
2	Electric Retail Revenues	0	0	0	0	0	0
3	PPFAC Revenue	0	0	0	0	0	0
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	0	0	0	0	0
7	Operating Expenses						
8	Fuel Expense	0	0	0	0	0	0
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	0	0	0	0	0	0
13	Other Operations & Maintenance Expense	0	0	0	0	(1,598)	(1,340)
14	Depreciation and Amortization	0	0	0	0	0	0
15	Taxes Other than Income	0	0	0	0	0	0
16	Income Taxes	0	121	0	7	0	513
17	Total Operating Expenses	0	121	0	7	(1,598)	(828)
18	Operating Income	0	(121)	0	(7)	1,598	828
19	Rate Base - Original Cost	(16,188)	(14,673)	(919)	(835)	0	(0)
20	Rate Base - RCND	(9,421)	(9,202)	(919)	(836)	0	(0)

<u>Supporting Exhibits</u>
(a) & (b) AECC Exhibit KCH-2, p. 1
(c) & (d) AECC Exhibit KCH-3, p. 1
(e) & (f) AECC Exhibit KCH-4, p. 1
(g) & (h) AECC Exhibit KCH-5, p. 1
(i) & (j) AECC Exhibit KCH-6, p. 1
(k) & (l) AECC Exhibit KCH-7, p. 1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

Line No.		Payroll Expense Adjustment		Short-Term Incentive Compensation Expense Adjustment		Long-Term Incentive Compensation Expense Adjustment	
		Total Company (a)	ACC Jurisdictional (b)	Total Company (c)	ACC Jurisdictional (d)	Total Company (e)	ACC Jurisdictional (f)
1	Operating Revenues						
2	Electric Retail Revenues	14	14	0	0	0	0
3	PPFAC Revenue	(14)	(14)	0	0	0	0
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	(0)	0	0	0	0
7	Operating Expenses						
8	Fuel Expense	(14)	(14)	0	0	0	0
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	(14)	(14)	0	0	0	0
13	Other Operations & Maintenance Expense	(1,365)	(1,130)	(2,484)	(1,773)	(1,542)	(1,294)
14	Depreciation and Amortization	0	0	0	0	0	0
15	Taxes Other than Income	(91)	(76)	(233)	(195)	0	0
16	Income Taxes	0	467	0	753	0	495
17	Total Operating Expenses	(1,469)	(753)	(2,716)	(1,216)	(1,542)	(799)
18	Operating Income	1,469	753	2,716	1,216	1,542	799
19	Rate Base - Original Cost	0	(0)	0	(0)	0	(0)
20	Rate Base - RCND	0	(0)	0	(0)	0	(0)

Line No.		SERP Expense Adjustment		Severance Expense Adjustment		Credit Card Processing Fees Expense Adjustment	
		Total Company (g)	ACC Jurisdictional (h)	Total Company (i)	ACC Jurisdictional (j)	Total Company (k)	ACC Jurisdictional (l)
1	Operating Revenues						
2	Electric Retail Revenues	0	0	0	0	0	0
3	PPFAC Revenue	0	0	0	0	0	0
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	0	0	0	0	0
7	Operating Expenses						
8	Fuel Expense	0	0	0	0	0	0
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	0	0	0	0	0	0
13	Other Operations & Maintenance Expense	(1,130)	(948)	(254)	(218)	(3,476)	(3,478)
14	Depreciation and Amortization	0	0	0	0	0	0
15	Taxes Other than Income	0	0	0	0	0	0
16	Income Taxes	0	363	0	83	0	1,329
17	Total Operating Expenses	(1,130)	(585)	(254)	(135)	(3,476)	(2,149)
18	Operating Income	1,130	585	254	135	3,476	2,149
19	Rate Base - Original Cost	0	(0)	0	(0)	0	0
20	Rate Base - RCND	0	(0)	0	(0)	0	0

Supporting Exhibits
(a) & (b) AECC Exhibit KCH-8, p. 1
(c) & (d) AECC Exhibit KCH-9, p. 1
(e) & (f) AECC Exhibit KCH-10, p. 1
(g) & (h) AECC Exhibit KCH-11, p. 1
(i) & (j) AECC Exhibit KCH-12, p. 1
(k) & (l) AECC Exhibit KCH-13, p. 1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

Line No.		Generation Overhaul Expense Adjustment		Jurisdictional Allocation Adjustment		Total Adjustments	
		Total Company (a)	ACC Jurisdictional (b)	Total Company (c)	ACC Jurisdictional (d)	Total Company (e)	ACC Jurisdictional (f)
1	Operating Revenues						
2	Electric Retail Revenues	0	0	(2,715)	(2,715)	(2,702)	(2,702)
3	PPFAC Revenue	0	0	2,715	2,715	2,702	2,702
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	0	(0)	0	(0)	0
7	Operating Expenses						
8	Fuel Expense	0	0	2,715	2,715	2,702	2,702
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	0	0	2,715	2,715	2,702	2,702
13	Other Operations & Maintenance Expense	(1,946)	(1,862)	0	(4,944)	(13,793)	(16,965)
14	Depreciation and Amortization	0	0	0	(4,248)	(2,389)	(5,392)
15	Taxes Other than Income	0	0	0	(746)	(324)	(1,020)
16	Income Taxes	0	712	0	3,265	0	9,232
17	Total Operating Expenses	(1,946)	(1,150)	2,715	(3,960)	(13,804)	(12,463)
18	Operating Income	1,946	1,150	(2,715)	3,960	13,804	12,463
19	Rate Base - Original Cost	0	(0)	0	(62,117)	(57,269)	(114,736)
20	Rate Base - RCND	0	(0)	0	(110,196)	(66,935)	(172,193)

EXHIBIT KCH-2

AECC Bonus Tax Depreciation Expense ADIT Adjustment

Line No.		Total Company AECC Bonus Tax Depr. ADIT Adjustment ($000) (a)	Jurisdictional AECC Bonus Tax Depr. ADIT Adjustment ($000) (b)		Line No.
1	**Operating Revenues**				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	**Operating Expenses**				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	106		16
17	Total Operating Expenses	0	106		17
18	Operating Income	0	(106)		18
19	Rate Base - Original Cost	(15,887)	(12,814)		19
20	Rate Base - RCND	(34,299)	(27,664)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		172		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(1,525)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		(171)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(1,525)}$		25

<u>Supporting Schedules/Data Source</u>
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Bonus Tax Depreciation Expense ADIT Adjustment

			AECC Recommended[1]			TEP Proposed[2]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Accumulated Deferred Income Taxes (ADIT)	190	($168,923,600)	80.66%	($136,246,714)	($175,121,198)	80.66%	($141,245,438)	$6,197,598	80.66%	$4,998,723
2	Accumulated Deferred Income Taxes (ADIT) - Other Property	282	$19,241,437	80.66%	$15,519,339	$41,326,508	80.66%	$33,332,234	($22,085,071)	80.66%	($17,812,895)
3	Accumulated Deferred Income Taxes (ADIT) - Other	283	$51,043,022	97.18%	$49,604,518	$51,043,022	97.18%	$49,604,518	$0	97.18%	$0
4	Total ADIT		($98,639,141)		($71,122,857)	($82,751,668)		($58,308,685)	($15,887,473)		($12,814,172)

1. Data Source: TEP Response to AECC Data Request No. 1.3.
2. Data Source: TEP Pro Forma Rate Base - Accumulated Deferred Income Taxes Workpaper.

EXHIBIT KCH-3

AECC Sundt & San Juan 2 Material & Supplies Regulatory Asset Adjustment

Line No.		Total Company AECC Sundt & San Juan 2 M&S Adjustment ($000) (a)	Jurisdictional AECC Sundt & San Juan 2 M&S Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	3		16
17	Total Operating Expenses	0	3		17
18	Operating Income	0	(3)		18
19	Rate Base - Original Cost	(409)	(409)		19
20	Rate Base - RCND	(409)	(409)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		5		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(49)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(43)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Sundt & San Juan 2 Material & Supplies Regulatory Asset Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Regulatory Asset (Beginning Balance)		$1,225,594	100.0%	$1,225,594	$1,225,594	100.0%	$1,225,594			
2	Less: Accumulated Amortization (Yr 1)		($408,531)		($408,531)	$0		$0			
3	Net Regulatory Asset	182.3	$817,063	100.0%	$817,063	$1,225,594	100.0%	$1,225,594	($408,531)	100.0%	($408,531)
4	Proposed Amortization Period (Yrs)		3		3	3		3			
5	Amortization Expense	407.3	$408,531	100.0%	$408,531	$408,531	100.0%	$408,531	$0	100.0%	$0

1. Data Source: TEP Pro Forma Rate Base - Sundt _ San Juan M_S Workpaper and Income - Sundt-San Juan M_S Workpaper.

EXHIBIT KCH-4

AECC 50.5% Co-Ownership of SGS 1 Adjustment Regulatory Asset Adjustment

Line No.		Total Company AECC Co-Ownership of SGS 1 Adjustment ($000) (a)	Jurisdictional AECC Co-Ownership of SGS 1 Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	(2,389)	(2,145)		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	1,016		16
17	Total Operating Expenses	(2,389)	(1,128)		17
18	Operating Income	2,389	1,128		18
19	Rate Base - Original Cost	(23,887)	(23,887)		19
20	Rate Base - RCND	(23,887)	(23,887)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,830)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(2,843)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(4,673)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC 50.5% Co-Ownership of SGS 1 Adjustment Regulatory Asset Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Steam Production Plant in Service										
2	Land & Land Rights	310	$0	100.0%	$0	$1,166,906	100.0%	$1,166,906	($1,166,906)	100.0%	($1,166,906)
3	Structures & Improvements	311	0	100.0%	0	24,028,906	100.0%	24,028,906	(24,028,906)	100.0%	(24,028,906)
4	Boiler Plant Equipment	312	0	100.0%	0	46,602,538	100.0%	46,602,538	(46,602,538)	100.0%	(46,602,538)
5	Turbogenerator Units	314	0	100.0%	0	14,978,815	100.0%	14,978,815	(14,978,815)	100.0%	(14,978,815)
6	Accessory Electric Equipment	315	0	100.0%	0	1,978,251	100.0%	1,978,251	(1,978,251)	100.0%	(1,978,251)
7	Misc. Power Plant Equipment	316	0	100.0%	0	1,327,646	100.0%	1,327,646	(1,327,646)	100.0%	(1,327,646)
8	Total		$0		$0	$90,083,062		$90,083,062	($90,083,062)		($90,083,062)
9	Steam Production Plant Accumulated Depreciation										
10	Land & Land Rights	310	$0	100.0%	$0	($1,372,775)	100.0%	($1,372,775)	$1,372,775	100.0%	$1,372,775
11	Structures & Improvements	311	0	100.0%	0	(18,316,603)	100.0%	(18,316,603)	18,316,603	100.0%	18,316,603
12	Boiler Plant Equipment	312	0	100.0%	0	(32,458,827)	100.0%	(32,458,827)	32,458,827	100.0%	32,458,827
13	Turbogenerator Units	314	0	100.0%	0	(12,249,649)	100.0%	(12,249,649)	12,249,649	100.0%	12,249,649
14	Accessory Electric Equipment	315	0	100.0%	0	(1,266,485)	100.0%	(1,266,485)	1,266,485	100.0%	1,266,485
15	Misc. Power Plant Equipment	316	0	100.0%	0	(532,212)	100.0%	(532,212)	532,212	100.0%	532,212
16	Total		$0		$0	($66,196,552)		($66,196,552)	$66,196,552		$66,196,552
17	Steam Production Plant Net Book Value										
18	Land & Land Rights	310	$0		$0	($205,869)		($205,869)	$205,869		$205,869
19	Structures & Improvements	311	0		0	5,712,303		5,712,303	(5,712,303)		(5,712,303)
20	Boiler Plant Equipment	312	0		0	14,143,711		14,143,711	(14,143,711)		(14,143,711)
21	Turbogenerator Units	314	0		0	2,729,165		2,729,165	(2,729,165)		(2,729,165)
22	Accessory Electric Equipment	315	0		0	711,766		711,766	(711,766)		(711,766)
23	Misc. Power Plant Equipment	316	0		0	795,433		795,433	(795,433)		(795,433)
24	Total		$0		$0	$23,886,510		$23,886,510	($23,886,510)		($23,886,510)
25	Net Regulatory Asset (= Ln. 24)	182.3	$0	100.0%	$0	$23,886,510	100.0%	$23,886,510	($23,886,510)	100.0%	($23,886,510)
26	Regulatory Asset Amortization Expense[2]										
27	Land & Land Rights	310	$0	89.8%	$0	($20,587)	89.78%	($18,484)	$20,587	89.8%	$18,484
28	Structures & Improvements	311	0	89.8%	0	571,230	89.78%	512,866	(571,230)	89.8%	(512,866)
29	Boiler Plant Equipment	312	0	89.8%	0	1,414,371	89.78%	1,269,862	(1,414,371)	89.8%	(1,269,862)
30	Turbogenerator Units	314	0	89.8%	0	272,917	89.78%	245,032	(272,917)	89.8%	(245,032)
31	Accessory Electric Equipment	315	0	89.8%	0	71,177	89.78%	63,904	(71,177)	89.8%	(63,904)
32	Misc. Power Plant Equipment	316	0	89.8%	0	79,543	89.78%	71,416	(79,543)	89.8%	(71,416)
33	Total		$0		$0	$2,388,651		$2,144,597	($2,388,651)		($2,144,597)

1. Data Source: TEP Responses to AECC Data Request No. 10.2 and 16.1.
2. Note: TEP's response to AECC DR No. 16.1 indicates the ACC regulatory asset amortization expense is $2,165,307 derived by using FERC account 310-316 jurisdictional allocation factors. AECC has used the related steam plant depreciation expense jurisdictional allocation factors to develop its adjustment above.

EXHIBIT KCH-5

AECC Springerville Unit 1 2006 Lease Acquisition Rate Base Adjustment

Line No.		Total Company AECC SGS 1 2006 Lease Acquisition Adjustment ($000) (a)	Jurisdictional AECC SGS 1 2006 Lease Acquisition Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	121		16
17	Total Operating Expenses	0	121		17
18	Operating Income	0	(121)		18
19	Rate Base - Original Cost	(16,188)	(14,675)		19
20	Rate Base - RCND	(9,421)	(9,202)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		196		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(1,747)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		63		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(1,488)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Springerville Unit 1 2006 Lease Acquisition Rate Base Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Plant in Service										
2	Land & Land Rights	310	$264,751	89.8%	$237,701	$223,159	89.8%	$200,358	$41,592	89.8%	$37,343
3	Structures & Improvements	311	10,161,249	89.8%	9,123,052	8,564,917	89.8%	7,689,821	1,596,332	89.8%	1,433,232
4	Boiler Plant Equipment	312	27,966,787	89.8%	25,109,359	23,573,204	89.8%	21,164,678	4,393,582	89.8%	3,944,680
5	Turbogenerator Units	314	7,165,280	95.7%	6,854,205	6,039,615	95.7%	5,777,409	1,125,666	95.7%	1,076,796
6	Accessory Electric Equipment	315	4,348,967	89.8%	3,904,623	3,665,744	89.8%	3,291,207	683,223	89.8%	613,416
7	Miscellaneous Power Plant Equipment	316	770,943	95.7%	737,473	649,828	95.7%	621,616	121,115	95.7%	115,857
8	Total Plant in Service		$50,677,977		$45,966,413	$42,716,467		$38,745,090	$7,961,510		$7,221,324
9	Accumulated Depreciation										
10	Land & Land Rights	310	$126,160	89.8%	$113,270	$0	89.8%	$0	$126,160	89.8%	$113,270
11	Structures & Improvements	311	4,842,084	89.8%	4,347,358	0	89.8%	0	4,842,084	89.8%	4,347,358
12	Boiler Plant Equipment	312	13,326,858	89.8%	11,965,224	0	89.8%	0	13,326,858	89.8%	11,965,224
13	Turbogenerator Units	314	3,414,431	95.7%	3,266,196	0	95.7%	0	3,414,431	95.7%	3,266,196
14	Accessory Electric Equipment	315	2,072,389	89.8%	1,860,649	0	89.8%	0	2,072,389	89.8%	1,860,649
15	Miscellaneous Power Plant Equipment	316	367,373	95.7%	351,424	0	95.7%	0	367,373	95.7%	351,424
16	Total Accumulated Depreciation		$24,149,296		$21,904,121	$0		$0	$24,149,296		$21,904,121
17	Net Plant in Service										
18	Land & Land Rights		$138,591		$124,431	$223,159		$200,358	($84,568)		$0
19	Structures & Improvements		5,319,165		4,775,695	8,564,917		7,689,821	(3,245,752)		0
20	Boiler Plant Equipment		14,639,928		13,144,135	23,573,204		21,164,678	(8,933,276)		0
21	Turbogenerator Units		3,750,849		3,588,009	6,039,615		5,777,409	(2,288,766)		0
22	Accessory Electric Equipment		2,276,578		2,043,975	3,665,744		3,291,207	(1,389,166)		0
23	Miscellaneous Power Plant Equipment		403,570		386,049	649,828		621,616	(246,258)		0
24	Total Plant in Service		$26,528,681		$24,062,293	$42,716,467		$38,745,090	($16,187,786)		($14,682,797)

1. Data Source: TEP Rate Base - SGS Unit 1 Lease Equity Adjustment. FERC amounts derived using FERC account percentages shown on p. 3.

AECC Springerville Unit 1 2006 Lease Acquisition Rate Base Adjustment

Line No.	Description	Total Plant Amount	2006 Purchase Percentage[2]	2006 Purchase Amount
	(a)	(b)	(c)	(d)
1	**Springerville Unit 1 Net Book Value as of 6/30/2015[1]**			
2	Plant in Service - Account 101	$ 359,418,280	14.1%	$ 50,677,977
3	Accumulated Depreciation Reserve - Account 108	171,271,606	14.1%	$24,149,296
4	Net Book Value (= Ln. 1 - Ln. 2)	$ 188,146,674		$ 26,528,681

Line No.	Description	FERC Account	FERC Account Allocation Percent[3]	2006 Purchase Amount
	(a)	(b)	(c)	(d)
5	**Spread of 2006 Net Book Values to FERC Accounts[4]**			
6	**Plant in Service - Account 101**			
7	Land and Land Rights	310	0.5%	264,751
8	Structures and improvements	311	20.1%	10,161,249
9	Boiler plant equipment	312	55.2%	27,966,787
10	Turbogenerator units	314	14.1%	7,165,280
11	Accessory electric equipment	315	8.6%	4,348,967
12	Miscellaneous power plant equipment	316	1.5%	770,943
13	Total			50,677,977
14	**Accumulated Depreciation Reserve - Account 108**			
15	Land and Land Rights	310	0.5%	126,160
16	Structures and improvements	311	20.1%	4,842,084
17	Boiler plant equipment	312	55.2%	13,326,858
18	Turbogenerator units	314	14.1%	3,414,431
19	Accessory electric equipment	315	8.6%	2,072,389
20	Miscellaneous power plant equipment	316	1.5%	367,373
21	Total			24,149,296

1. **Data Source: TEP Response to AECC 11.3.**
2. **Data Source: TEP Witness Kentton Grant Direct Testimony, p. 30.**
3. **Data Source: TEP Rate Base - SGS Unit 1 Lease Equity Adjustment.**
4. **The net book value excludes acquisition adjustment and accumulated deferred income tax amounts which appear to be related to TEP's 2015 purchase of 35.4% interest in Unit 1.**

EXHIBIT KCH-6

AECC Springerville Unit 1 Capitalized Legal Costs Rate Base Adjustment

Line No.		Total Company AECC SGS 1 2014/15 Cap. Legal Costs Adjustment ($000) (a)	Jurisdictional AECC SGS 1 2014/15 Cap. Legal Costs Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	7		16
17	Total Operating Expenses	0	7		17
18	Operating Income	0	(7)		18
19	Rate Base - Original Cost	(919)	(835)		19
20	Rate Base - RCND	(919)	(836)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		11		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(99)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		(0)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(88)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Springerville Unit 1 Capitalized Legal Costs Rate Base Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Plant in Service										
2	Land & Land Rights	310	$0	89.8%	$0	$4,801	89.8%	$4,311	($4,801)	89.8%	($4,311)
3	Structures & Improvements	311	0	89.8%	0	184,274	89.8%	165,446	(184,274)	89.8%	(165,446)
4	Boiler Plant Equipment	312	0	89.8%	0	507,176	89.8%	455,357	(507,176)	89.8%	(455,357)
5	Turbogenerator Units	314	0	95.7%	0	129,942	95.7%	124,301	(129,942)	95.7%	(124,301)
6	Accessory Electric Equipment	315	0	89.8%	0	78,868	89.8%	70,810	(78,868)	89.8%	(70,810)
7	Miscellaneous Power Plant Equipment	316	0	95.7%	0	13,981	95.7%	13,374	(13,981)	95.7%	(13,374)
8	Total Plant in Service		$0		$0	$919,042		$833,598	($919,042)		($833,598)

1. Data Source: See derivation on p. 3.

AECC Springerville Unit 1 Capitalized Legal Expense Rate Base Adjustment

Line No.	Description		Total Plant Amount
	(a)		(c)
1	**Springerville Unit 1 2014/2015 Acquisition Fee Amount Included in Rate Base[1]**		
2	AECC Recommended Disallowance	$	919,042

Line No.	Description	FERC Account	FERC Account Allocation Percent[2]		FERC Account Amount
	(a)	(b)	(c)		(d)
3	**Spread of Acquisition Fees to FERC Accounts**				
4	**Plant in Service - Account 101**				
5	Land and Land Rights	310	0.5%	$	4,801
6	Structures and improvements	311	20.1%		184,274
7	Boiler plant equipment	312	55.2%		507,176
8	Turbogenerator units	314	14.1%		129,942
9	Accessory electric equipment	315	8.6%		78,868
10	Miscellaneous power plant equipment	316	1.5%		13,981
11	Total			$	919,042

1. Data Source: TEP Response to AECC Data Request No. 10.2 (clarified by D. Lewis e-mail on 5/26/2016).
2. Data Source: TEP Rate Base - SGS Unit 1 Lease Equity Adjustment.

EXHIBIT KCH-7

AECC Springerville Unit 1 Legal Expense Adjustment

Line No.		Total Company AECC SGS 1 Legal Expense Adjustment ($000) (a)	Jurisdictional AECC SGS 1 Legal Expense Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(1,598)	(1,340)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	513		16
17	Total Operating Expenses	(1,598)	(828)		17
18	Operating Income	1,598	828		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,343)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(1,343)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Springerville Unit 1 Legal Expense Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Administrative & General Expenses										
2	Outside Services	923	$0	83.9%	$0	$1,597,513	83.9%	$1,340,437	($1,597,513)	83.9%	($1,340,437)

1. Data Source: TEP Response to AECC Data Request 10.1.

Comparison of Legal Expenses for TEP's Retail Jurisdiction

		ACC Jurisdiction[1]				
Line No.		**2011**	**2012**	**2013**	**2014**	**Test Year 12 Mos. End. 6/30/2015**
1	Unadjusted	2,342,462	1,619,431	1,419,891	2,222,637	3,638,621
2	DSM & REST Adjustment	(58,051)				(357,950)
3	Springerville 3 & 4 Adjustment	4,162				(2,395)
4	Power Supply Management					(22,619)
5	Adjusted	2,288,572	1,619,431	1,419,891	2,222,637	3,255,658

Avg. = 1,775,965

Data Sources:
1. TEP Supplemental Response to AECC Data Request 10.1.

EXHIBIT KCH-8

AECC Payroll Expense Adjustment

Line No.		Total Company AECC Payroll Expense Adjustment ($000) (a)	Jurisdictional AECC Payroll Expense Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	14	14		2
3	PPFAC Revenue	(14)	(14)		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	(0)		6
7	Operating Expenses				7
8	Fuel Expense	(14)	(14)		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	(14)	(14)		12
13	Other Operations & Maintenance Expense	(1,365)	(1,130)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	(91)	(76)		15
16	Income Taxes	0	467		16
17	Total Operating Expenses	(1,469)	(753)		17
18	Operating Income	1,469	753		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,222)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(1,222)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Payroll Expense Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Adjustment	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Operations						
2	Steam Prod Oper-Supervision	500	6,623,859	6,933,211	153,145	6,777,004	(156,208)
3	Fuel - Steam	501	572,531	599,270	13,237	585,768	(13,502)
4	Steam Expenses	502	7,846,852	8,213,321	181,420	8,028,272	(185,049)
5	Electric Expenses	505	2,606,785	2,728,529	60,269	2,667,054	(61,475)
6	Steam Prod-Misc Expense	506	1,930,923	2,021,102	44,643	1,975,566	(45,536)
7	Other Prod Oper-Supervision	546	41,644	43,589	963	42,607	(982)
8	Misc. Other Pw Gen Exp	549	107	112	2	109	(3)
9	Sys Cntrol/Load Dispatch	556	1,081,004	1,131,490	24,993	1,105,997	(25,493)
10	Prod Expense-Other	557	257,063	269,068	5,943	263,006	(6,062)
11	Trans-Oper Supv & Engr	560	1,198,247	1,254,209	27,704	1,225,951	(28,258)
12	Dist-Oper Supv & Engr	580	438,001	458,457	10,127	448,128	(10,329)
13	Dist-Load Dispatching	581	451,781	472,881	10,445	462,227	(10,654)
14	Dist-Station Expenses	582	173,895	182,017	4,020	177,916	(4,101)
15	Dist-Overhead Line Exp	583	405,478	424,415	9,375	414,853	(9,562)
16	Dist-Underground Line Exp	584	188,035	196,817	4,347	192,383	(4,434)
17	Dist-Light/Signal Exp	585	76	79	2	77	(2)
18	Dist-Meter Expenses	586	685,887	717,919	15,858	701,744	(16,175)
19	Dist-Customer Install Exp	587	45,620	47,751	1,055	46,675	(1,076)
20	Dist-Misc Expense	588	3,167,598	3,315,534	73,235	3,240,834	(74,700)
21	Meter Reading Expense	902	439	460	10	449	(10)
22	Cust Rec/Collection Exp	903	6,052,473	6,335,140	139,934	6,192,407	(142,733)
23	Customer Assistance Exp	908	59,761	62,552	1,382	61,142	(1,409)
24	Informational/Instrct Adv Exp	909	6,315	6,610	146	6,461	(149)
25	A&G Salaries	920	20,958,164	21,936,965	484,556	21,442,720	(494,245)
26	Outside Services	923	62,512	65,431	1,445	63,957	(1,474)
27	Injuries & Damages	925	67,970	71,145	1,571	69,542	(1,603)
28	Pensions & Benefits	926	1,278,055	1,337,744	29,549	1,307,604	(30,140)
29	Misc. General Expenses	930	171,654	179,671	3,969	175,623	(4,048)
30	Load Dispatch-Reliability	5611	686,184	718,231	15,865	702,049	(16,182)
31	Load Dispatch-Monitor and Operation Transmiss	5612	807,012	844,701	18,658	825,670	(19,031)
32	Load Dispatch-Transmission Service and Schedu	5613	582,935	610,159	13,478	596,412	(13,747)
33	Total Operations	Various	58,448,862	61,178,579	1,351,346	59,800,208	(1,378,372)
34	Total Maintenance	Various	18,330,858	18,330,858	0	18,330,858	-
35	Total Operations & Maintenance	Various	76,779,720	79,509,437	1,351,346	78,131,065	(1,378,372)
36	Taxes Other Than Income Taxes [2]	408			89,119		(90,901)

Data Sources:
1. TEP Income - Payroll Expense workpaper.
2. TEP Income - Payroll Tax Expense workpaper.
Note: TEP's Income - Payroll Expense workpaper identifies FERC Account 930 payroll expense as "General Advertising Exp" (Account 930.1).
However, TEP's revenue requirement model places this adjustment in Account 930.2, Misc. General Expenses. AECC's adjustment is made to Account 930.2.

AECC
Payroll Expense Adjustment Derivation
Test Year Ended June 30, 2015

Line No.		Wages Charged to O&M: Total Payroll	Wages Charged to O&M: Clearing Account Allocations to O&M	Wages Charged to O&M: Deduct SGS Unit 1 - External owners	Exclude A&G Payroll Capitalized through A&G Loader	Deduct SGS Unit 3 Wages	Deduct SGS Unit 4 Wages	Total O&M Wages
1	Jun-14	74,298,455	15,808,352	(3,385,007)	(5,289,752)	(7,789,279)	(7,134,089)	66,508,680
2	Jun-15	76,779,720	17,193,144	(3,365,954)	(6,234,868)	(7,227,233)	(8,518,905)	68,625,903
3		151,078,174	33,001,496	(6,750,962)	(11,524,619)	(15,016,512)	(15,652,994)	135,134,583
4						2 Year Average O&M Wages		67,567,291
5						Average Wage Rate Increase	2016	2%
6								1,351,346

Data Source: TEP Income - Payroll Expense workpaper.

AECC Payroll Tax Expense Adjustment Derivation

Line No.	TEP Employer Tax - Ended June 2015			
1	Social Security	7,900,994	per Form 941	
2	Medicare	2,450,273	per Form 941	
3	FUTA/SUTA	143,232	per FUTA and SUTA returns	
4		10,494,500		
		Wages, tips and other compensation from Form 941		
5	Q3 2014	62,328,958		
6	Q4 2014	35,209,774		
7	Q1 2015	27,716,883		
8	Q2 2015	33,876,917		
9		159,132,532	0.066	effective tax rate (A)
10	Payroll Adjustment		1,351,346	(B) (from Payroll Expense Adj)
11	Employer Payroll Tax Adjustment		$ 89,119	(A) X (B)
12	TEP Recommended Payroll Tax Adjustment		180,020	

Data Source: TEP Income - Payroll Tax Expense workpaper.

EXHIBIT KCH-9

AECC Short-Term Incentive Compensation Adjustment

Line No.		Total Company AECC Short-Term Incentive Comp. Adjustment ($000) (a)	Jurisdictional AECC Short-Term Incentive Comp. Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(2,484)	(1,773)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	(233)	(195)		15
16	Income Taxes	0	753		16
17	Total Operating Expenses	(2,716)	(1,216)		17
18	Operating Income	2,716	1,216		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,972)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(1,972)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Short-Term Incentive Compensation Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Taxes Other Than Inc Tax	408	$527,194	$566,200	$333,310	($232,890)
2	Steam Prod Oper Supervision	500	$109,412	$153,796	$90,537	($63,258)
3	Steam Prod Misc Expense	506	$1,283,253	$1,761,093	$1,036,731	($724,362)
4	Steam Prod Mnt Elec Plnt	514	$498,759	$668,144	$393,324	($274,820)
5	Trans Misc Oper Expense	566	$751,760	$1,147,303	$675,415	($471,888)
6	Trans Maint Stn Equip	570	$59,125	$98,181	$57,800	($40,381)
7	Dist Oper Supv & Engr	580	$0	$2,298	$1,354	($945)
8	Dist Misc Expense	588	$370,190	$444,714	$261,788	($182,926)
9	Dist Maint Misc Plant	598	$93,479	$113,025	$66,534	($46,491)
10	Cust Rec/Collection Exp	903	$197,685	$295,032	$173,687	($121,345)
11	A&G Salaries	920	$3,038,685	$2,866,556	$2,309,451	($557,105)
12	Total		$6,929,542	$8,116,343	$5,399,931	($2,716,411)

1. Data Sources: TEP Income - Short Term Incentive Compensation workpaper and TEP Income - Short Term Incentive Compensation - Revised workpaper (provided in TEP's April 14, 2016 supplemental response to UDR 1.001). The amount of AECC's adjustment reflects TEP's filed case.

Derivation of AECC's Short-Term Incentive Compensation Adjustment

Line No.	Account	Average of 6/30/14 and 6/30/15 w/o 2017 Escalation	Average of 6/30/14 and 6/30/15 w/o 2017 Escalation 60%	7/1/14-6/30/15 Unadjusted	TEP Adjustments - Originally-Filed	Adjusted TEP Expenses- Originally-Filed	AECC Adjustment
1	408	555,516	333,310	527,194	39,006	566,200	(232,890)
2	500	150,896	90,537	109,412	44,384	153,796	(63,258)
3	506	1,727,885	1,036,731	1,283,253	477,840	1,761,093	(724,362)
4	514	655,540	393,324	498,759	169,385	668,144	(274,820)
5	566	1,125,691	675,415	751,760	395,543	1,147,303	(471,888)
6	570	96,334	57,800	59,125	39,056	98,181	(40,381)
7	580	2,256	1,354	-	2,298	2,298	(945)
8	588	436,313	261,788	370,190	74,524	444,714	(182,926)
9	598	110,890	66,534	93,479	19,546	113,025	(46,491)
10	903	289,479	173,687	197,685	97,347	295,032	(121,345)
11	920-Net	3,849,086	2,309,451	3,038,685	(172,129)	2,866,556	(557,105)
12	Total	8,999,886	5,399,931	6,929,542	1,186,800	8,116,343	(2,716,411)

Data Sources: TEP's Income - Short Term Incentive Compensation workpaper;
Income - Short Term Incentive Compensation - Revised workpaper.

EXHIBIT KCH-10

AECC Long-Term Incentive Compensation Adjustment

Line No.		Total Company AECC Long-Term Incentive Comp. Adjustment ($000) (a)	Jurisdictional AECC Long-Term Incentive Comp. Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(1,542)	(1,294)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	495		16
17	Total Operating Expenses	(1,542)	(799)		17
18	Operating Income	1,542	799		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,296)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(1,296)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Long-Term Incentive Compensation Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Administrative & General Salaries	920	$491,910	$1,541,834	$0	($1,541,834)

1. Data Source: TEP Income - Long Term Incentive Compensation workpaper.
TEP has provided a correction in Income - Long Term Incentive Compensation - Revised
in its March 18, 2016 supplemental response to UDR 1.001. The amount of AECC's adjustment reflects TEP's filed case.

EXHIBIT KCH-11

AECC SERP Adjustment

Line No.		Total Company AECC SERP Adjustment ($000) (a)	Jurisdictional AECC SERP Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(1,130)	(948)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	363		16
17	Total Operating Expenses	(1,130)	(585)		17
18	Operating Income	1,130	585		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(950)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 29 + Ln. 30)		(950)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC SERP Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Pensions & Benefits	926	$564,903	$1,129,807	$0	($1,129,807)

1. Data Source: TEP Income - Pension_Benefits workpaper.

EXHIBIT KCH-12

AECC Severance Expense Adjustment

Line No.		Total Company AECC Severance Expense Adjustment ($000) (a)	Jurisdictional AECC Severance Expense Adjustment ($000) (b)		Line No.
1	**Operating Revenues**				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	**Operating Expenses**				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(254)	(218)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	83		16
17	Total Operating Expenses	(254)	(135)		17
18	Operating Income	254	135		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(218)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(218)		25

<u>Supporting Schedules/Data Source</u>
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Severance Expense Adjustment

Line No.	Description	FERC Acct	AECC Recommended Total Company Amount	AECC Recommended ACC Jurisdictional Allocation Percent	AECC Recommended ACC Jurisdictional Amount	TEP Proposed[1] Total Company Amount	TEP Proposed[1] ACC Jurisdictional Allocation Percent	TEP Proposed[1] ACC Jurisdictional Amount	AECC Adjustment Total Company Amount	AECC Adjustment ACC Jurisdictional Allocation Percent	AECC Adjustment ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Distribution O&M Expenses										
2	Operation Supervision & Engineering	580	$0	100.0%	$0	$30,000	100.0%	$30,000	($30,000)	100.0%	($30,000)
3	Administrative & General Expenses										
4	A&G Salaries	920	$0	83.9%	$0	$223,853	83.9%	$187,830	($223,853)	83.9%	($187,830)
5	Total Adjustment		$0		$0	$253,853		$217,830	($253,853)		($217,830)

1. Data Source: TEP Response to Uniform Data Request No. 1.043.

EXHIBIT KCH-13

AECC Credit Card Processing Fees Adjustment

Line No.		Total Company AECC Credit Card Processing Fees Adjustment ($000) (a)	Jurisdictional AECC Credit Card Processing Fees Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(3,476)	(3,476)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	1,329		16
17	Total Operating Expenses	(3,476)	(2,146)		17
18	Operating Income	3,476	2,146		18
19	Rate Base - Original Cost	0	0		19
20	Rate Base - RCND	0	0		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(3,482)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		0		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(3,482)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Credit Card Processing Fees Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Customer Records & Collection Expenses	903	$0	$3,475,500	$0	($3,475,500)

1. Data Source: TEP Income - Credit Card Processing Fees workpaper.
TEP has provided a correction in Income - Credit Card Processing Fees-Revised in its April 14, 2016 supplemental response to UDR 1.001.
The amount of AECC's adjustment reflects TEP's filed case.

EXHIBIT KCH-14

AECC Generation Overhaul Expense Adjustment

Line No.		Total Company: AECC Generation Overhaul Expense Adjustment ($000) (a)	Jurisdictional: AECC Generation Overhaul Expense Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(1,946)	(1,862)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	712		16
17	Total Operating Expenses	(1,946)	(1,150)		17
18	Operating Income	1,946	1,150		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,865)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(1,865)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Normalized Generation Overhaul Expense Adjustment

Generation Overhaul Expense by Plant

			AECC Recommended			TEP Proposed[2]			AECC Adjustment		
Line No.	Plant	Test Year Total Company Actual[1]	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	TEP Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	AECC Recommended Adjustment	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Four Corners	$0	$854,175	95.66%	$817,092	$2,700,063	95.66%	$2,582,841	($1,845,888)	95.66%	($1,765,750)
2	Navajo	$2,561,527	$1,902,764	95.66%	$1,820,156	$1,384,559	95.66%	$1,324,449	$518,205	95.66%	$495,707
3	San Juan	$4,464,000	$1,488,000	95.66%	$1,423,400	$2,188,235	95.66%	$2,093,235	($700,235)	95.66%	($669,835)
4	Luna	$1,185,383	$1,409,192	95.66%	$1,348,013	$944,201	95.66%	$903,209	$464,991	95.66%	$444,804
5	Gila	$232,778	$620,695	95.66%	$593,748	$641,176	95.66%	$613,340	($20,482)	95.66%	($19,593)
6	Springerville	$0	$3,735,385	95.66%	$3,573,216	$3,419,588	95.66%	$3,271,129	$315,797	95.66%	$302,087
7	Sundt/Irvington	$0	$1,223,299	95.66%	$1,170,190	$ 1,582,059	95.66%	$1,513,375	($358,760)	95.66%	($343,185)
8	ICT	$0	$306,432	95.66%	$293,128	$626,471	95.66%	$599,273	($320,039)	95.66%	($306,145)
9	Total Expense (Acct 512)	$8,443,688	$11,539,941		$11,038,943	$13,486,351		$12,900,852	($1,946,411)		($1,861,909)

1. TEP's direct filing workpapers used 2015 budget numbers (Total = $8,074,926) as the basis for its adjustments. The amounts shown in Column (b) have been adjusted to reflect 2015 actual expenses.
2. Data Source: TEP As-Filed Pro Forma Income - Overhaul_Outage Normalization Workpaper.

EXHIBIT KCH-15

AECC Return on Equity Adjustment

Line No.		Total Company AECC Capital Structure Adjustment (a)	Jurisdictional AECC Incentive Compensation Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	0		16
17	Total Operating Expenses	0	0		17
18	Operating Income	0	0		18
19	Rate Base - Original Cost	0	0		19
20	Rate Base - RCND	0	0		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		0		22
23	TEP As-Filed OCRB Rate Base (KCH-1, p. 2, Ln. 1)		2,104,678		23
24	Total AECC OCRB Rate Base Adjustments before ROE Adjustment		(52,619)		24
25	Total Adjusted OCRB Rate Base before ROE Adjustment (Ln. 23 + Ln. 24)		2,052,059		25
26	Weighted Cost of Capital before AECC ROE Adjustment		7.34%		26
27	Total Adjusted OCRB Rate Base after ROE Adjustment (Ln. 19 + Ln. 25)		2,052,059		27
28	Weighted Cost of Capital after AECC ROE Adjustment		7.01%		28
29	OCRB Revenue Req't Impact ([(Ln. 27 x Ln. 28) - (Ln. 25 x Ln. 26)] x Ln. 21)		(10,826)		29
30	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		30
31	Total Revenue Requirement Impact (Ln. 22 + Ln. 29 + Ln. 30)		(10,826)		31

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

2012 Vertically-Integrated Electric Utility Rate Case Summary
Cases with ROE Determinations as Reported by SNL Financial

Decision Date	State	Company	Case Identification	Common Equity /Total Cap (%)	Return on Equity (%)
1/25/2012	South Carolina	Duke Energy Carolinas LLC	D-2011-271-E	53.00	**10.50**
1/27/2012	North Carolina	Duke Energy Carolinas LLC	D-E-7, Sub 989	53.00	**10.50**
2/15/2012	Michigan	Indiana Michigan Power Co.	C-U-16801	42.07	**10.20**
2/23/2012	Oregon	Idaho Power Co.	D-UE-233	49.90	**9.90**
2/27/2012	Florida	Gulf Power Co.	D-110138-EI	38.50	**10.25**
2/29/2012	North Dakota	Northern States Power Co. - MN	C-PU-10-657	NA	**10.40**
3/29/2012	Minnesota	Northern States Power Co. - MN	D-E-002/GR-10-971	52.56	**10.37**
4/4/2012	Hawaii	Hawaii Electric Light Co	D-2009-0164	55.91	**10.00**
4/26/2012	Colorado	Public Service Co. of CO	D-11AL-947E	56.00	**10.00**
5/2/2012	Hawaii	Maui Electric Company Ltd	D-2009-0163	56.86	**10.00**
5/7/2012	Washington	Puget Sound Energy Inc.	D-UE-111048	48.00	**9.80**
5/15/2012	Arizona	Arizona Public Service Co.	D-E-01345A-11-0224	53.94	**10.00**
6/7/2012	Michigan	Consumers Energy Co.	C-U-16794	42.07	**10.30**
6/15/2012	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-118 (elec)	49.31	**10.40**
6/18/2012	Wyoming	Cheyenne Light Fuel Power Co.	D-20003-114-ER-11 (elec)	54.00	**9.60**
6/19/2012	South Dakota	Northern States Power Co. - MN	D-EL11-019	53.04	**9.25**
6/26/2012	Michigan	Wisconsin Electric Power Co.	C-U-16830	43.51	**10.10**
6/29/2012	Hawaii	Hawaiian Electric Co.	D-2010-0080	56.29	**10.00**
7/9/2012	Oklahoma	Oklahoma Gas and Electric Co.	Ca-PUD201100087	NA	**10.20**
7/16/2012	Wyoming	PacifiCorp	D-20000-405-ER-11	52.10	**9.80**
9/13/2012	Texas	Entergy Texas Inc.	D-39896	49.92	**9.80**
9/19/2012	Utah	PacifiCorp	D-11-035-200	52.10	**9.80**
10/24/2012	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-121 (Elec)	51.61	**10.30**
11/9/2012	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-118 (elec)	59.09	**10.30**
11/28/2012	Wisconsin	Wisconsin Electric Power Co.	D-05-UR-106 (WEP-Elec)	52.09	**10.40**
11/29/2012	California	Liberty Utilities CalPeco Ele	A-12-02-014	51.50	**9.88**
12/12/2012	Missouri	Union Electric Co.	C-ER-2012-0166	52.30	**9.80**
12/13/2012	Florida	Florida Power & Light Co.	D-120015-EI	NA	**10.50**
12/13/2012	Kansas	Kansas City Power & Light	D-12-KCPE-764-RTS	51.82	**9.50**
12/14/2012	Wisconsin	Northern States Power Co - WI	D-4220-UR-118 (elec)	52.37	**10.40**
12/19/2012	South Carolina	South Carolina Electric & Gas	D-2012-218-E	52.18	**10.25**
12/20/2012	California	Southern California Edison Co.	Ap-12-04-015	48.00	**10.45**
12/20/2012	California	San Diego Gas & Electric Co.	Ap-12-04-016 (Elec)	52.00	**10.30**
12/20/2012	California	Pacific Gas and Electric Co.	Ap-12-04-018 (Elec)	52.00	**10.40**
12/20/2012	Kentucky	Kentucky Utilities Co.	C-2012-00221	NA	**10.25**
12/20/2012	Kentucky	Louisville Gas & Electric Co.	C-2012-00222 (elec.)	NA	**10.25**
12/20/2012	Oregon	PacifiCorp	D-UE-246	52.10	**9.80**
12/21/2012	North Carolina	Virginia Electric & Power Co.	D-E-22, Sub 479	51.00	**10.20**
12/26/2012	Washington	Avista Corp.	D-UE-120436	47.00	**9.80**
			MEDIAN:	52.10	**10.20**
			OBSERVATIONS:	34	39

2015 - Q1 2016 Vertically-Integrated Electric Utility Rate Case Summary
Cases with ROE Determinations as Reported by SNL Financial

Decision Date	State	Company	Case Identification	Common Equity /Total Cap (%)	Return on Equity (%)
1/23/2015	Wyoming	PacifiCorp	D-20000-446-ER-14	51.43	**9.50**
2/24/2015	Colorado	Public Service Co. of CO	D-14AL-0660E	56.00	**9.83**
3/25/2015	Washington	PacifiCorp	D-UE-140762	49.10	**9.50**
3/26/2015	Minnesota	Northern States Power Co. - MN	D-E-002/GR-13-868	52.50	**9.72**
4/23/2015	Michigan	Wisconsin Public Service Corp.	C-U-17669	NA	**10.20**
4/29/2015	Missouri	Union Electric Co.	C-ER-2014-0258	51.76	**9.53**
5/26/2015	West Virginia	Appalachian Power Co.	C-14-1152-E-42T	47.16	**9.75**
9/2/2015	Missouri	Kansas City Power & Light	C-ER-2014-0370	50.09	**9.50**
9/10/2015	Kansas	Kansas City Power & Light	D-15-KCPE-116-RTS	50.48	**9.30**
11/19/2015	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-124 (Elec)	50.47	**10.00**
11/19/2015	Michigan	Consumers Energy Co.	C-U-17735	41.50	**10.30**
12/3/2015	Wisconsin	Northern States Power Co - WI	D-4220-UR-121 (Elec)	52.49	**10.00**
12/11/2015	Michigan	DTE Electric Co.	C-U-17767	38.03	**10.30**
12/15/2015	Oregon	Portland General Electric Co.	D-UE-294	50.00	**9.60**
12/17/2015	Texas	Southwestern Public Service Co	D-43695	51.00	**9.70**
12/18/2015	Idaho	Avista Corp.	C-AVU-E-15-05	50.00	**9.50**
12/30/2015	Wyoming	PacifiCorp	D-20000-469-ER-15	51.44	**9.50**
1/6/2016	Washington	Avista Corp.	D-UE-150204	48.5	**9.5**
2/23/2016	Arkansas	Entergy Arkansas Inc.	D-15-015-U	28.46	**9.75**
3/16/2016	Indiana	Indianapolis Power & Light Co.	Ca-44576	37.33	**9.85**
			MEDIAN:	50.09	**9.71**
			OBSERVATIONS:	19	20

EXHIBIT KCH-16

Page 2 CONFIDENTIAL

AECC Jurisdictional Allocation Adjustment

Line No.		Total Company AECC Jurisdictional Allocation Adjustment ($000) (a)	Jurisdictional AECC Jurisdictional Allocation Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	(2,715)	(2,715)		2
3	PPFAC Revenue	2,715	2,715		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	(0)	0		6
7	Operating Expenses				7
8	Fuel Expense	2,715	2,715		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	2,715	2,715		12
13	Other Operations & Maintenance Expense	0	(4,944)		13
14	Depreciation and Amortization	0	(4,248)		14
15	Taxes Other than Income	0	(748)		15
16	Income Taxes	0	3,265		16
17	Total Operating Expenses	2,715	(3,960)		17
18	Operating Income	(2,715)	3,960		18
19	Rate Base - Original Cost	0	(62,117)		19
20	Rate Base - RCND	0	(110,196)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(6,424)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x AECC WACC x Ln. 21)		(7,066)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		(554)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(14,043)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

Derivation of AECC's Recommended Demand Jurisdictional Allocation Factor

DEMAND ALLOCATION - 2015											
Line No.	**Date**	**Retail System Peak**	**SRP**	**NTUA**	**TOUA**	**Shell**	**Trico**	**Sub-Total FERC**	**FERC w/SRP Removed**	**Total**	**Line No.**
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = Sum(b:f)	(h) = (g) -(b)	(i) = (a) + (j)	
1	June, 2015										1
2	July, 2015					CONFIDENTIAL					2
3	August, 2015										3
4	September, 2015										4
5	Total										5
6	Average (Line 5/ 4)										6
7	Demand Allocation Factor (Line 6 - (a)/(i) and (h)/(i)	91.53%							8.47%	100.00%	7

EXHIBIT KCH-17

AECC New Corporate Headquarters Building Return Adjustment

Line No.	Description	FERC Account	ACC Jurisdiction Test Year Net Book Value[1]	ACC Jurisdiction Return at TEP Proposed WACC[2] 7.34%	ACC Jurisdiction Return at TEP TY Average Cost of Debt[3] 4.32%	ACC Jurisdiction Headquarters Return Adjustment -3.0145%
1	Land	389	7,521,380	551,829	325,098	(226,731)
2	Structures & Improvements	390	60,140,795	4,412,415	2,599,476	(1,812,939)
3	Furniture & Equipment	391	1,162,146	85,264	50,232	(35,033)
4	Network Equipment	391	3,139,038	230,305	135,679	(94,626)
5	Communication Equip	397	628,171	46,088	27,152	(18,936)
6	Miscellaneous Equipment	398	36,468	2,676	1,576	(1,099)
7	Total		72,627,999	5,328,578	3,139,213	(2,189,365)

Line		
8	ACC Jurisdiction Return Adjustment	($2,189,365)
9	Gross Revenue Conversion Factor[4]	1.6223
10	Revenue Requirement Impact	($3,551,835)

1. Data Source: TEP's Response to AECC 15.1.
2. Data Source: TEP recommended WACC, see Schedule D-1, p. 1 of 2.
3. Data Source: TEP TY recommended cost of debt based on the average of TEP's cost of long term debt as reported in TEP Schedule D-2, p. 1 of 2.
4. Data Source: TEP recommended WACC, see Schedule C-3, p. 1 of 1.

EXHIBIT KCH-18

Exhibit KCH-18

TEP's Non-Confidential Responses
To Parties' Data Requests
Referenced in Testimony & Exhibits

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
January 14, 2016

AECC 1.3

Bonus tax depreciation. Using TEP's direct case as a starting point, what is the impact on the TEP's revenue requirement resulting from the five year extension of bonus tax depreciation in H.R. 2029 (as signed into law by President Obama on December 18, 2015)? Please provide the adjustments necessary on both a Total Company and ACC Jurisdictional basis necessary to reflect the impact of this extension on TEP's requested revenue increase. Please provide the workpapers used to support this response in Excel format with formulas intact.

RESPONSE: January 4, 2016

TEP is in the process of evaluating the H.R. 2029 through its year end close process and will respond as soon as possible.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: January 14, 2016

For an updated Accumulated Deferred Income Tax pro forma adjustment that includes the impacts of the extension of bonus depreciation, see AECC 1.3 Bonus - Rate Base - Accumulated Deferred Income Taxes.xlsm. This update would reduce the overall revenue requirement by approximately $1.5 million. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

Tucson Electric Power Company
RATE BASE PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Accumulated Deferred Income Taxes
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	January 13, 2016
PREPARED BY:	Donye' Bonsu
CHECKED BY:	
REVIEWED BY:	Jay Rademacher

		Total Company		ACC Jurisdictional	
FERC ACCT	**FERC ACCOUNT DESCRIPTION**	**DEBIT**	**CREDIT**	**DEBIT**	**CREDIT**
190	ADIT	-	168,923,600		$136,246,714
282	ADIT - Other Property	19,241,437	-	$15,519,338	
283	ADIT - Other	51,043,022	-	$49,604,518	
	ENTRY TOTAL	**$70,284,459**	**$168,923,600**	**$65,123,856**	**$136,246,714**
	NET ENTRY		**$98,639,141**		**$71,122,858**

Reason for Adjustment

To adjust rate base to reflect the pro forma test year ADIT.

AECC 7.5

Please refer to STF 3.3 Jurisdictional Allocation-Confidential, provided in TEP's response to Staff Data Request 3.3, the "Demand Summary" tab.

a. Please explain why the SRP and Shell demand has been removed in the calculation of the jurisdictional demand allocation factors.

b. Please provide the expiration dates of the SRP and Shell wholesale contracts.

RESPONSE:

a.-b. The SRP and Shell wholesale contract will expire May 31, 2016 and December 31, 2017 respectively. New Rates will not become effected until the first part of 2017; therefore, the demand allocation proposed by the company reflects the appropriate known and measurable long term Wholesale demand levels.

RESPONDENT:

David Lewis

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC TENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 13, 2016

AECC 10.1

Legal expenses.

a. Please identify by FERC account the amount of outside legal expense included in the test year retail revenue requirement.

b. Are there any differences between TEP's per-books outside legal expense and the amount included in the test year retail revenue requirement? If so, please show where these adjustments are presented in TEP's filing.

c. Please identify by FERC account the amount of outside legal expense included in TEP's requested test year retail revenue requirement in Docket No. E-01993A-12-0291.

d. Please identify by FERC account the amount of outside legal expense incurred by TEP in each of the following years: 2012, 2013, and 2014.

e. Please refer to the Direct Testimony of Michael E. Sheehan, p. 45, lines 18-19. Are any of the outside legal expenses associated with the co-owners and former lessors of Springerville Unit 1 included in the test year retail revenue requirement? If so, please identify this amount, indicate the docket number(s) of the cases, and explain the rationale for recovering these expenses from ratepayers.

RESPONSE: **April 18, 2016**

a. Please see AECC 10.1a Legal Expenses.xlxs. The Excel file is <u>not</u> identified by Bates numbers.

b. The differences between TEP's books outside legal expense and the amount included in the test year are identified in the file referenced in AECC 10.1a.

c. Please see AECC 10.1c Legal Expenses.xlxs. The Excel file is <u>not</u> identified by Bates numbers.

d. Please see AECC 10.1d Legal Expenses.xlxs. The Excel file is <u>not</u> identified by Bates numbers.

e Yes. There is $1,340,437 of outside legal expenses associated with the co-owners and former lessors of Springerville Unit 1 included in the test year retail revenue requirement. Below is a list of the case numbers and docket number:

Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade v. TEP
FERC Dkt. No. EL15-17-000

Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade v. TEP
Case No. 653898/2014
New York County Supreme Court

Alterna Springerville LLC, LDVF1 TEP LLC (via Wilmington Trust Company and William J. Wade as Trustees)
Case No. 01-15-0003-7373
American Arbitration Association

TEP v. Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade Consolidated Matter
Case No. 01-15-0003-2729
American Arbitration Association New York

The rationale for recovery is that these legal expenses were necessary in order to acquire the interests in SGS Unit 1. As such, they are considered transaction costs for the acquisition to provide service to customers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: May 13, 2016

In response to AECC 19.1, TEP provides the following. The legal expenses shown in AECC 10.1d Legal Expenses.xlxs are on a total Company basis. For the ACC jurisdictional basis, please see AECC 10.1d Legal Expenses ACC Basis.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

Tucson Electric Power
Legal Expenses
AECC 10.1a

FERC	Test Year Unadjusted Balance	REST & DSM Adjustment	Springerville Units 3 & 4	Power Supply Management	Test Year Adjusted Balance
0500	1,115.00	-	-	-	1,115.00
0502	-	-	-	-	-
0506	4,789.50	-	(2,394.72)	-	2,394.78
0556	-	-	-	-	-
0560	203.50	-	-	-	203.50
0590	-	-	-	-	-
0903	31,346.36	-	-	-	31,346.36
0908	16,945.95	-	-	-	16,945.95
0923	3,483,179.46	(357,949.73)	-	(22,619.00)	3,102,610.73
0926	101,041.56	-	-	-	101,041.56
	3,638,621.33	(357,949.73)	(2,394.72)	(22,619.00)	3,255,657.88

Tucson Electric Power
Legal Expenses
AECC 10.1c

FERC	Unadjusted Calendar Yr. 2011	REST & DSM	Springerville Units 3 & 4	Adjusted Calendar Yr. 2011
0417	(8,323.10)	-	8,323.10	-
0514	76,822.13	-	-	76,822.13
0556	5,410.85	-	-	5,410.85
0903	20,117.18	-	-	20,117.18
0908	1,849.00	-	-	1,849.00
0923	1,925,765.71	(58,051.48)	(4,161.54)	1,863,552.69
0926	320,820.19	-		320,820.19
	2,342,461.96	(58,051.48)	4,161.56	2,288,572.04

Tucson Electric Power
Legal Expenses
AECC 10.1d

FERC	DEC-12	Test Year Ended June 30, 2015 ACC %	ACC Jurisdiction Basis DEC-12
0500	-	89.782780%	-
0502	28,676.25	89.782780%	25,746.33
0506	-	89.782780%	-
0556	3,382.00	-	-
0560	560.00	-	-
0590	-	100.000000%	-
0903	32,374.88	100.000000%	32,374.88
0908	117,158.21	100.000000%	117,158.21
0923	1,672,679.97	83.907730%	1,403,507.79
0926	48,438.70	83.907730%	40,643.81
	1,903,270.01		1,619,431.02

FERC	DEC-13	Test Year Ended June 30, 2015 ACC %	ACC Jurisdiction Basis DEC-13
0500	12,636.25	89.782780%	11,345.18
0502	-	89.782780%	-
0506	-	89.782780%	-
0556	72.00	-	-
0560	17,828.92	-	-
0590	777.00	100.000000%	777.00
0903	27,586.75	100.000000%	27,586.75
0908	11,708.51	100.000000%	11,708.51
0923	1,445,192.93	83.907730%	1,212,628.58
0926	185,733.53	83.907730%	155,844.79
	1,701,535.89		1,419,890.81

FERC	DEC-14	Test Year Ended June 30, 2015 ACC %	ACC Jurisdiction Basis DEC-13
0500	62,575.08	89.782780%	56,181.65
0502	-	89.782780%	-
0506	4,789.50	89.782780%	4,300.15
0556	-	-	-
0560	869.50	-	-
0590	-	100.000000%	-
0903	36,146.66	100.000000%	36,146.66
0908	14,523.00	100.000000%	14,523.00
0923	2,279,615.48	83.907730%	1,912,773.60
0926	236,822.27	83.907730%	198,712.19
	2,635,341.49		2,222,637.25

AECC 11.3

Please refer to the Direct Testimony of Kentton C. Grant, pp. 31-32. Regarding TEP's proposal to include $42.7 million of the 2006 SGS 1 acquisition in rate base:

a. Please explain the current accounting treatment on TEP's books of this $42.7 million, as well as the original $48 million acquisition cost.

b. Has any portion of this acquisition cost been amortized? If so, please explain and identify the amortization schedule.

c. Has TEP requested to include any portion of the 2006 acquisition investment in a prior rate case? If yes, please explain. If not, please explain why TEP has not requested inclusion in rate base previously.

d. What is the net book value of SGS 1 on January 2, 2015 (when TEP completed the purchase)? Please separately identify original cost, capital improvements, and accumulated depreciation. What was the net book value of the SGS Coal Handling Facility on June 30, 2015 (at the end of the test year)? Please separately identify original cost, capital improvements, and accumulated depreciation.

e. What was the net book value of the SGS 1 on June 30, 2015 (at the end of the test year)? Please separately identify original cost, capital improvements, and accumulated depreciation.

f. What is the amount of ADIT for the SGS 1 on June 30, 2015?

RESPONSE:

a. TEP's current accounting reflects $36 million of net assets as discussed in part b of this response. These assets are currently accounted for as a component of the plant in service and accumulated depreciation accounts.

b. The original $48 million lease asset acquisition was treated as a lease equity investment and was amortized to $36 million as of December 31, 2014.

c. No. TEP has not previously requested rate base treatment of the referenced lease equity investment since SGS Unit 1 was reflected in rates as an operating lease expense. As described in Mr. Grant's direct testimony, when TEP purchased the lease equity interest, it paid for the right to receive all of the remaining lease equity rents, as well as for the residual value of the asset at the end of the lease. Now that the lease term has ended, TEP is seeking to include a portion of the original lease equity investment in rate base as a cost of acquiring the asset. However, the portion of the original lease equity investment requested in rate base is higher, on a percentage basis, than the portion requested for the SGS coal handling facilities. That is because the reduction in lease equity rents achieved by TEP, when it amended the lease in 2006, was fully reflected in the SGS Unit 1 revenue requirement in the 2008 rate order.

d.-f. See AECC 11.2 and 11.3 SGS NBV and ADIT.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Rigo Ramirez / Jason Rademacher

WITNESS:

Kentton Grant / Dallas Dukes

Tucson Electric Power Company
Rate Case Test Year Ended 06/30/2015
AECC 11.2 & 11.3 SGS1 and SGSCH Net Book Value & ADIT

Springerville Unit 1

	1/2/2015	6/30/2015
Plant in Service - Account 101	358,470,749	359,418,280
Accumulated Reserve - Account 108	(168,658,726)	(171,271,606)
Acquisition Adjustment - Account 114	(40,636,573)	(40,636,573)
Amortization of Acq. Adj. Account 115	-	655,926
Net Book Value	149,175,450	148,166,027
ADIT		(9,892,156)

Springerville Coal Handling*

	4/5/2015	6/30/2015
Plant in Service - Account 101	206,670,828	179,094,730
Accumulated Reserve - Account 108	(90,824,298)	(78,367,861)
Acquisition Adjustment - Account 114	24,700,725	18,445,964
Amortization of Acq. Adj. Account 115	-	(84,828)
Net Book Value	140,547,255	119,088,005
ADIT		(4,327,551)

*The amounts include coal handling related rolling stock which is not associated with the Springerville Coal Handling Facility lease.

AECC 15.1

Follow up to TEP's response to AECC Data Request 11.4. In response to AECC Data Request No. 11.4, TEP provided the costs of its new headquarters building included in rate base in the current rate case. As a follow-up, please provide the following:

a. Please provide a breakdown of the amounts shown for the new TEP headquarters in 11.4(b) by FERC account. In addition, please include both the Total Company and the ACC jurisdictional allocation for each FERC account amount.

b. Please provide a description of the $3.3 million capital improvements that were necessary on the new TEP headquarters building.

c. Please provide the Total Company amounts by FERC account (both cost and accumulated depreciation) that TEP included in its last rate case (Docket No. E-01933A-12-0291) for the new headquarters building.

d. Please reconcile any differences in the Total Company headquarters original cost amount provided in TEP's response to 11.4 with the headquarters gross rate base included in TEP's ast rate case, Docket No. E-01933A-12-029. (See TEP's responses to AECC Data Requests 9.1 and 11.8 in that docket.) If the headquarters' original cost has increased since the last rate case, please provide an explanation for the increase.

RESPONSE:

a. The amounts provided below reflect the response to RUCO 7.20a. AECC 11.4a was prepared based on information using TEP's Utility Plant report. However, subsequent to AECC 11.4a information related to the headquarters building was updated for the response to RUCO 7.20a. The amounts reflect changes for the removal of end user computer equipment (391-CP) such as PC's, laptops and I-pads, also (303-software) was removed. After further consideration these type of assets should not be directly attributable to the building but rather stand-alone in nature. Please see tabs labeled "AECC 15.1a Part 1" for rate base and "AECC 15.1a Part 2" for ACC Jurisdictional in AECC 15.1 Support.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

b. The $3.3 million capital improvements provided in response to AECC 11.4a have been removed from the response to RUCO 7.20a. The capital improvements included leasehold improvements related to the old leased downtown building, these are not part of the new headquarters building and have also subsequently been fully amortized and retired from plant in-service in September 2015.

c. Please see attached file AECC 15.1 2012 TEP RC DR AECC 9.1 and 9.2.pdf, Bates Nos. TEP\024256-024257, for New HQ Building cost and accumulated depreciation included in the last rate case.

d. The increase of $3.9M since the last rate case is due to an addition of a security system, parking lot, network equipment and office furniture. Please see tab labeled "AECC 15.1d" in the attached excel file "AECC 15.1 Support.xlsx". The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Chrissy Cuevas (a part 1, b, d)/ Bernadette Porter (a part 2, c.)

WITNESS:

Dallas Dukes / Frank Marino

Tucson Electric Power
New Headquarter Building
AECC 15.1a Part 1

Ferc	Description	Original Cost	Accumulated Depreciation	Balance at June 30, 2015
E389	Land	8,549,937.60	0.00	8,549,937.60
E390	Structures & Improvements	72,957,362.70	4,585,467.09	68,371,895.61
E391	Furniture & Equipment	8,559,226.70	7,227,474.81	1,331,751.89
E391	Network Equipment	7,689,575.44	4,115,188.73	3,574,386.71
E397	Communication Equip	873,133.72	158,825.40	714,308.32
E398	Miscellaneous Equipment	50,023.47	8,555.31	41,468.16
Total		98,679,259.63	16,095,511.35	82,583,748.28

Tucson Electric Power
New Headquarter Building
AECC 15.1a Part 2

		ACC Jurisdictional				
Ferc	Description	ACC Jurisdiction Rate	ACC Jurisdiction Cost	ACC Jurisdiction Rate	ACC Jurisdiction Accumulated Deprn	ACC Net Book Value
E389	Land	87.97%	7,521,380.11	88.10%	-	7,521,380.11
E390	Structures & Improvements	87.97%	64,180,591.97	88.10%	4,039,796.51	60,140,795.46
E391	Furniture & Equipment	87.97%	7,529,551.73	88.10%	6,367,405.31	1,162,146.42
E391	Network Equipment	87.97%	6,764,519.51	88.10%	3,625,481.27	3,139,038.24
E397	Communication Equip	87.97%	768,095.73	88.10%	139,925.18	628,170.55
E398	Miscellaneous Equipment	87.97%	44,005.65	88.10%	7,537.23	36,468.42
Total			86,808,144.70		14,180,145.50	72,627,999.20

Exhibit KCH-18

AECC 16.1

Please refer to Schedule B-2, p. 4.

a. Does the $25,112 (thousand) regulatory asset entry in the "SGS CHF" column include the $23,886,510 regulatory asset being requested by TEP for the share of leasehold improvements attributed to the 50.5% Springerville Unit 1 owner (as identified in Attachment AECC 10.2 SGS U1 LH Improvements 50.5)?

b. If so, why is this regulatory asset classified in Schedule B-2 as being related to the coal handling facility?

c. Please identify the annual ACC jurisdictional revenue requirement being requested for the $23,886,510 regulatory asset, separately identifying return and amortization expense. Please provide the proposed amortization schedule and indicate where in TEP's filing the amortization expense is included or identified.

d. Does the $25,112 (thousand) regulatory asset entry in the "SGS CHF" column include the $1,112 (thousand) "Sundt and San Juan M&S" regulatory asset identified in Schedule B-2, p. 3?

e. If so, why is this regulatory asset classified in Schedule B-2 as being related to the coal handling facility?

f. Please identify the annual ACC jurisdictional revenue requirement being requested for the $1,112 (thousand) "Sundt and San Juan M&S" regulatory asset, separately identifying return and amortization expense. Please provide the proposed amortization schedule and indicate where in TEP's filing the amortization expense is included or identified.

RESPONSE:

a. Yes. As explained in company witness Kent Grant testimony, the leasehold improvements associated with the 50.5% co-owner share were reclassified as a regulatory asset and remain on the same 10-year amortization schedule approved in TEP's last rate case.

b. The column title should have been more inclusive or possibly a new column should have been prepared for the regulatory asset. The regulatory asset entry under the column SGS CHF includes the following:

SGS Unit 1 Leasehold Improvements	$23,886,510
Sundt and San Juan Materials & Supplies	1,225,594
Regulatory Assets	$25,112,104

c. The annual ACC jurisdictional revenue requirement the Company is requesting is $4,688,755. This is made up of $2,165,307 of amortization expense and $2,523,448 or return. The amortization expense is included in the Depreciation and Amortization Expense Annualization pro forma adjustment. Please see attached Regulatory Asset Amortization schedule for additional detail and FERC accounts.

d. See AECC 16.1(b) above.

e. See AECC 16.1(b) above.

f. The annual ACC jurisdictional revenue requirement the Company is requesting is $537,984. This is comprised of $408,531 of amortization expense and $129,423 return. The amortization expense is included in the Sundt and San Juan Material & Supply pro forma adjustment. Please see attached Regulatory Asset Amortization file for additional detail and FERC accounts.

RESPONDENT:

Rigo Ramirez

WITNESS:

Kentton Grant

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 4, 2016

RUCO 5.1

Credit Card Processing Fees – Please answer the following questions as they relate to Credit Card Processing Fees:

a. In the Company's pro forma adjustment for credit card processing fees, do year 1, year 2, and year 3 refer to 2016, 2017, and 2018? If no, what years do they refer to?

b. In the Company's pro forma adjustment for credit card processing fees, please update the 2015 estimated volume and dollars to actual.

c. In year 1 why does the Company believe credit card usage will increase by 50 percent, 10 percent in year 2, and 10 percent in year 3, or 70 percent overall?

d. Please provide a copy of all contracts between TEP and the credit card vendors.

e. Currently does the Company credit card fee of $3.50 to TEP customers not cover the credit card vendor expenses, TEP has to pay? If no, please provide the amount that is under collected along with the supporting calculations of this amount.

f. How are card paying customers "paying their fair share" if under the Company's proposal non-credit card customers now have to pick-up some of their expenses.

g. How does the Company's proposal not create subsidizes for credit card paying customers at the expense of those that do not pay by credit card?

h. How does the Company's proposal follow cost of service ratemaking (i.e. cost causation)?

i. If the customer has money withdrawn from his/her bank account automatically, does the Company have to pay a fee to the bank?

j. If yes to i., does the Company charge a bank fee to these customers?

RESPONSE:

a. No, they related to 2017, 2018, and 2019.

b. Please refer to the attached Excel file: Income – Credit Card Processing Fees-Revised.xlsm provided in response to UDR 1.001, as supplemented.

c. The increases were based on estimates provided by two independent industry leaders in utility credit card payment processing. It is not a figure calculated by TEP.

According to the research and analysis, utilities who do not charge a convenience fee see double the volume of transactions over those who do charge a fee.

d. The responsive file is competitively sensitive confidential with the ownership of the document held by the contractor. TEP attempted to gain permission to provide the file, but permission was denied.

e. The $3.50 fee represents 100% of the third party transaction costs associated with the credit card payments. The fee is paid directly to the third party vendor by the customer making the payment. TEP does not incur any of these costs.

f. Customers can pay their TEP bill in a number of ways: by check, cash, automatic bank account deduction or credit card. The Company's cost to process these payments varies by type of remittance and its overall processing costs are impacted by customers' behavior. TEP's proposal is in response to consistent feedback from TEP customers indicating dissatisfaction with the high fee that is imposed when paying their bill by credit card. The Company has experienced a growing trend that customers prefer to pay their utility bills by credit cards but realized that customers do not understand why a fee is imposed when other credit card fees for other services are embedded in the market price rather than as an added fee. The cost to Company currently varies by payment method therefore this approach is now more consistent across all customers. The approach still aligns with cost recovery as the credit card customers are still paying $1.00 toward the transaction.

This proposal will create a slight subsidy for customers paying by credit card even though such customers pay a minimal fee. The Company will continue to solicit vendors that will commit to charging a significantly lower fee that will result in less subsidy.

g. Please refer to 5.1(f) above.

h. Please refer to 5.1(f) above.

i. Yes, the depository bank assesses a fee for each withdrawal transaction.

j No, the Company does not.

RESPONDENT:

Brian Bub / Rigo Ramirez

WITNESS:

Denise Smith

RUCO 5.2

Long-Term Incentive Compensation – Please answer the following questions as they relate to long-term incentive compensation:

a. To clarify the Company is seeking long-term incentive compensation of $1,349,782 in the test year and $1,049,924 as a pro forma adjustment for a total of $2,399,706 in long-term incentive expense in this case. If no please explain.

b. Why did the Company not request long-term incentive compensation in its last rate case?

c. Has the Company in prior rate cases asked for long-term incentive compensation? If so, please provide the docket number, along with the Commission decision relating to the Company's request.

d. Why is the Company using a two year average as opposed to a three year average?

e. What Company executives or officers are eligible for the program?

f. List the names of the executives or officers in d. above along with the total long-term incentive compensation provided to them by fiscal year for the test year and three prior years. The test year and prior year amount should reconcile to your pro forma adjustment.

g. Provide a sub account that breaks-out the long-term compensation amounts between salary and payroll taxes for the years noted in f., the test year and prior year amount should reconcile to your pro forma adjustment.

h. From the Company's pro-forma adjustment $180,098 has been capitalized. Please explain to what accounts this amount was allocated to and how this amount was allocated

i. Was any long-term incentive compensation between 7/1/14 through 12/31/14 capitalized? If so, please provide the amount and explain to what accounts this amount was allocated to and how this amount was allocated.

j. Please explain the Fortis Merger long-term incentive compensation expense offset to the Company's pro-forma adjustment in the amount of $2,534,690, and how it was calculated.

k. Please provide a copy of any and all long-term incentive compensation program document(s), and explain how the performance units and restricted stock units relate to the performance goals, if not already provided.

l. Please provide a copy of the Company's benchmarking study.

m. What is the capitalization percentage for the test year?

RESPONSE: **April 4, 2016**

a. No. While responding to data request AECC 5.1, the Company discovered that the amount listed as Fortis Merger LTI Compensation expense was incorrect. As a result the Pro Forma adjustment was updated accordingly. The Company is seeking long-term incentive compensation of $491,910 in the test year and $1,191,919 as a pro forma adjustment for a total of $1,683,829 in long-term incentive expense in this case

b. Because of the size of the revenue request in the last rate case, the Company decided to not request long-term incentive compensation in this last rate case, but reserved the right to request it in this case.

c. Not in the last two rate cases.

d. The Company used the same two year methodology as it did for the payroll adjustment.

e./f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. The Long-Term Incentive Compensation Pro Forma Adjustment does not include payroll taxes.

h. The $180,098 capitalized amount was allocated to FERC 107 via the A&G Allocation.

i. No long-term incentive compensation between 7/1/14 through 12/31/14 was capitalized.

j. The Fortis Merger triggered the payout of all outstanding long-term incentive awards resulting in the accelerated recognition of compensation expense. Compensation expense on these annual awards is typically recognized ratably over a three-year term. In order to normalize the pro forma adjustment, the amount related to the accelerated recognition of compensation expense as a result of the Fortis Merger was deducted. This amount was calculated as follows:

Total Estimated Additional Comp Expense in 2014	$2,680,890
Multiplied by: TEP Mass. Allocation Percentage	x 80.46%
	2,157,044
Add: Payroll Taxes on LTI Payouts	377,646
	$2,534,690

The Payroll Taxes on LTI Payouts amount listed above should not have been included in the Long-Term Incentive Compensation Pro Forma Adjustment. The pro forma adjustment was subsequently updated in a recent data request as referred to in RUCO 5.2a above.

k. Please see the following attached files:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

File Name	Bates Numbers
RUCO 5.2k - 2012 LTI Term Sheet-Confidential.pdf	TEP\021453-021455
RUCO 5.2k - 2013 LTI Term Sheet-Confidential.pdf	TEP\021456-021459
RUCO 5.2k - 2014 LTI Term Sheet-Confidential.pdf	TEP\021460-021463
RUCO 5.2k - 2015 LTI Term Sheet-Confidential.pdf	TEP\021464-021467

l. TEP is in the process of gathering this information and will provide it as soon as possible.

m. The capitalization percentage used in the Long-Term Incentive Compensation Pro Forma Adjustment for the test year was 24.8% for the period 7/1/14 through 12/31/14 and 26.8% for the period 1/1/15 through 6/30/15.

RESPONDENT:

Georgia Hale/ David Lewis/ Steve Bracamonte

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: April 14, 2016

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

e-f, l. Please see RUCO 5.2 (e f & l)-Confidential.pdf, Bates Nos. TEP\021565-021566, for the confidential responses to subparts e, f, and l.

RESPONDENT:

Georgia Hale (e. and f.) / Gabrielle Camacho (l)

WITNESS:

Frank Marino

STF 7.14

Severance Pay:

Reference UDR 1.043.

a. Please explain who was separated and why severance pay was paid.

b. What is the amount of severance the Company is requesting to recover in this rate case?

c. If the Company is seeking recovery, please explain why this is a recurring transaction.

RESPONSE:

a. The severance was paid in the ordinary course of business. Individual severance agreements contain confidentiality agreements that would preclude us from providing names of such employees and the details of the circumstances resulting in the severance payment without their consent. Although we cannot identify each employee individually, the severance payments are generally made to employees at the middle management or professional level or higher, and is consistent with requests made in prior rate cases.

b. As set forth in UDR 1.043 the amount the company is requesting to recover in this rate case is severance pay of $365,688 ($111,835 capitalized and $253,853 O&M). $223,853 of O&M was recorded in FERC Account 920 and $30,000 in FERC Account 580.

c. In the ordinary course of business there are situations which result in severance paid to particular employees. This occurs in any given year, therefore the Company does not deem this to be an extraordinary expense.

RESPONDENT:

Gabrielle Camacho

WITNESS:

Frank Marino

CONFIDENTIAL EXHIBIT KCH-19

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

EXHIBIT
AECC-8
ADMITTED

REDACTED

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport Minerals Corporation,

Arizonans for Electric Choice & Competition and

Noble Americas Energy Solutions LLC

Cost of Service/Rate Design

June 24, 2016

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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EXHIBITS

DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who pre-filed direct testimony in this case on behalf of Freeport Minerals Corporation and Arizonans for Electric Choice and Competition ("AECC")[1] on the subject of revenue requirement?

A. Yes, I am. My cost of service / rate design testimony is also being sponsored by Noble Americas Energy Solutions ("Noble Solutions") with respect to my discussion of buy-through programs and related topics. Noble Solutions is a retail energy supplier that serves over 15,000 commercial and industrial end-use customers in 16 states, the District of Columbia, and Baja California, Mexico, and supplies power to Arizona Public Service Company ("APS") that serves Experimental Rate Rider AG-1 ("AG-1") customers on the APS system.

Q. What is the purpose of your testimony in this phase of the proceeding?

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[1] Henceforth in this testimony, Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

A. My testimony addresses the general topics of cost of service, revenue allocation, and rate design. My testimony also includes specific discussions of the buy-through tariff presented by Tucson Electric Power Company ("TEP" or the "Company"), unbundled rates, the mobile home park rate schedule, the Lost Fixed Cost Recovery mechanism ("LFCR"), and rate design issues applicable to the Purchased Power and Fuel Adjustment Charge ("PPFAC").

SUMMARY

Q. What are the primary conclusions and recommendations presented in this phase of your testimony?

A. (1) As a general proposition, I support TEP's use of the 4CP – Average & Excess Demand ("4CP AED") method to allocate production demand and transmission costs to classes. However, I disagree with two details related to the Company's application of the 4CP AED method. Accordingly, I am recommending two specific changes to TEP's calculation of the 4CP AED allocator, which I describe in my testimony.

(2) I have identified five cost allocation errors and conceptual flaws in TEP's cost-of-service study unrelated to the allocation of generation and transmission costs, which I have corrected in my testimony. Two of these errors were acknowledged by TEP in discovery.

(3) TEP's proposed revenue allocation contains a very large subsidy for the Residential class, whereas the General Service ("GS") and Large General Service ("LGS") classes would have rates that are 16.7% and 25.0% above cost, respectively. *Using TEP's overall revenue proposal as a baseline*, I recommend

reducing the GS and LGS revenue allocation such that the rates for each class are no more than 12.5% above cost of service. I also recommend reducing the High Voltage (138 kV) revenue allocation by [redacted] to move this customer class to its cost of service, and fine-tuning the revenue allocation to Large Power Service ("LPS") to bring this class to its cost of service as well. The sum of these net reductions would be offset with a corresponding increase in the revenue allocation to the Residential class, which would also move this class closer to its cost of service, although a considerable subsidy would still remain in residential rates.

At AECC's proposed revenue requirement, I have apportioned my recommended revenue allocation as shown in Table KCH-5, which includes a buy-through reserve fund of $7,550,207 as explained below in my testimony. *For an alternate revenue requirement that may be approved by the Commission*, I recommend scaling down (or up as appropriate) each class's revenue allocation by an equal percentage of non-fuel revenues relative to my recommended rate spread at AECC's recommended revenue requirement shown in Table KCH-5, while still providing for the buy-through reserve fund of $7,550,207. As is the case for Table KCH-5, the buy-through reserve would be funded from a portion of the revenue reduction (relative to TEP's filed case) that would otherwise apply to customers in the classes eligible for the buy-through program, discussed below, which under my proposal would be LGS, LPS, and High Voltage.

(4) I recommend adoption of a buy-through program that is as similar as reasonably possible to the AG-1 program currently in effect in the APS service territory, but with a different funding mechanism than the APS program. While I

believe it would be preferable to allow Arizona customers full access to the electric power marketplace to take advantage of the benefits of competition as intended by the Arizona Legislature, a buy-through program represents a compromise that provides customers the opportunity to engage in market transactions and potentially reduce their energy costs, consistent with state policy, but without implementing full direct access service. A successful buy-through program will enhance the economic development climate of the TEP service territory and of the state generally.

I recommend adopting some of the features of the buy-through program presented by TEP, but modifying other features to make the program open to a wider variety of customers, making it a more viable option. I recommend changes to program scale, eligibility, pricing, terms of return to standard generation service, and the mechanics of fixed generation cost recovery. I also recommend a clarification to the program term.

Specifically:

(a) I recommend increasing the proposed 30 MW cap on participation proposed by TEP to 60 MW, and broadening the range of eligible customers by allowing customers to participate with a minimum load size of 3,000 kW (peak demand) and allowing aggregation of smaller loads in the LGS class owned by the same corporate entity to achieve that 3,000 kW threshold. I recommend that the term of the program will continue at least until the start of the first rate-effective period (following a general rate case order) occurring no less than four years from the starting date of the buy-through program.

(b) The monthly management fee of $0.004/kWh for buy-through service proposed by TEP is unreasonable and should be reduced to $0.002/kWh, based on the management fee review conducted by APS regarding its AG-1 program.

(c) Under the TEP program, the Generation Capacity component of the demand charge would continue to apply to 100% of the customer's billed demand. While some assignment of cost for generation reserves may be appropriate, the TEP proposal is more comparable to a stranded cost charge. The stranded cost approach should be rejected unless the customers are being provided with an opportunity to transition permanently to market pricing. Absent such an option, the going-forward charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billing load, priced at the unbundled Generation Capacity rate components for the customer's rate schedule. This pricing approach ties the charge for reserve capacity to TEP's planning reserve margin and is comparable to APS's AG-1 charge for reserve capacity.

My recommended 15% reserve capacity percentage is based on TEP's planning reserve margin and is comparable to the AG-1 reserve capacity charge levied by APS.

In addition, I recommend that the first $7,550,207 of any revenue requirement reduction apportioned to the classes eligible for the buy-through program be used to absorb TEP's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers. In this way, both TEP and the customer classes not eligible to participate in the buy-through program would be held harmless from adoption of the buy-through provision.

(d) If, prior to the end of the planned four-year term of the program, and absent Commission termination of the program, a buy-through customer seeks to return to standard generation service and does not provide one-year's notice, TEP proposes to charge the returning customer the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the customer back into the Company's generation planning. While I agree that this general approach is reasonable, I believe the proposed $20 per MWh mark-up is excessive and should be eliminated or significantly reduced to no greater than $4 per MWh.

(5) TEP's depiction of the components that make up each class's allocated costs by function and classification is distorted. I correct this error in order to accurately design unbundled LGS, LPS, and High Voltage rates.

(6) TEP's unbundled rate design is flawed in that the Company is improperly attempting to recover fixed generation-related costs in the unbundled Delivery-related components of the LGS, LPS, and High Voltage tariffs, contrary to the fundamentals of proper unbundled rate design. For this reason I recommend that TEP's proposed relationship between Delivery charges and Generation Capacity charges in its unbundled tariff for the LGS, LPS, and High Voltage classes be rejected. Instead, I recommend that the unbundled rate design presented in Exhibit KCH-20 attached to my testimony should be adopted. This unbundled rate design was prepared using my proposed rate spread at TEP's overall revenue requirement. The rate components in Exhibit KCH-20 should be scaled back as discussed in my testimony to the extent that lower class revenue requirements are approved in this case.

(7) TEP should be required to eliminate its proposed Delivery energy charges for demand-billed classes.

(8) The applicability criteria for Mobile Home Park Electric Service – GS-11F, and its proposed replacement rate schedule, GS-M-F, should be amended to remove restrictions on service to new customers or new facilities, or restrictions limiting the mobile home park rate schedule to customers served historically on the mobile home park rate. The tariff restrictions that prevent existing mobile home parks from switching to the mobile home park rate schedule are unjust and unreasonable and should be removed from the TEP tariff. At a minimum, the applicability should be amended such that there is no restriction on migrating to this rate schedule for any existing master-metered mobile home park.

(9) TEP's proposed changes to the LFCR mechanism should be rejected. The LFCR mechanism adopted in the last general rate case was the product of difficult negotiations. I am not persuaded that an LFCR is needed in the first instance, and I particularly disagree with levying this charge on LGS customers, as a significant part of TEP's concern regarding these customers can be addressed through rate design. Therefore, not only do I disagree with TEP's proposed changes, but I also recommend that LGS customers be exempted from this charge going forward.

(10) TEP's proposal to use a single percentage adjustment for the PPFAC is reasonable as the adjustment would be proportionate to each customer class's fuel costs. I support adoption of this change. However, TEP's proposal to change to a monthly reset of the PPFAC creates rate uncertainty from month to month and is potentially problematic. Although I am disinclined to support this change

on a standalone basis, I would not oppose this approach if it were adopted as a package in tandem with the 70/30 PPFAC risk sharing mechanism that I am recommending in my revenue requirement testimony.

<u>COST OF SERVICE</u>

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- *Separating* the utility's costs in accordance with the various *functions* of its system (e.g., generation [or production], transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for the utility's costs to the various customer classes based on principles of cost causation.

Q. What is the role of cost-of-service analysis in setting rates?

A. Each of the three steps above has an important role in the ratemaking process. Cost functionalization guides classification and allocation method selection based on the utility function served. If rates are unbundled by function, as they are required to be in Arizona, then separating the utility's costs by function also determines the generation-related, transmission-related, and distribution-related components of unbundled rates.

The classification of costs informs the selection of allocation methods, i.e., demand, energy, or customer-based. The classification of costs is also critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes guides the revenue allocation across customer classes, commonly referred to as "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

Q. Does TEP allocate generation plant costs between its retail customers and FERC-jurisdictional customers?

A. Yes.

Q. What approach has TEP used for allocating generation plant costs between TEP retail customers and FERC-jurisdictional customers?

A. TEP uses the four coincident peaks ("4CP") method for allocating generation plant costs between its state and federal jurisdictional loads. The 4CP method allocates fixed production costs based on the average of system peak demands in the four summer months, which is when TEP's production capacity requirements are determined.

Q. In your opinion, is the 4CP method appropriate for allocating TEP's jurisdictional generation plant costs?

A. Yes, it is. TEP's maximum system demands are driven by summer usage. Given the characteristics of TEP's system, the 4CP method properly aligns the allocation of the Company's fixed costs with cost causation.

Q. Please describe TEP's approach to class cost-of-service analysis.

A. As explained in the Direct Testimony of Craig A. Jones, the Company utilizes an embedded cost-of-service study to guide class revenue allocation and rate design. The Company has also conducted a marginal customer cost study, based on forward-looking costs, to guide its rate design for Residential and Small General Service customers.[2] TEP also utilizes the minimum-size method to classify certain distribution costs into customer-related and demand-related components.[3]

Q. What method does TEP use to allocate demand-related production and transmission costs to classes in the embedded cost study?

A. TEP uses the 4CP Average and Excess Demand ("4CP AED") method[4], utilizing the retail system 4CP load factor.

Q. What is your general assessment of TEP's approach to allocating demand-related production and transmission costs among rate classes?

A. As a general proposition, I support TEP's use of the 4CP AED method to allocate production demand and transmission costs to classes. However, I disagree with two details related to the Company's application of the 4CP AED method. Accordingly, I recommend two changes to TEP's calculation of the 4CP AED allocator, which I describe below.

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[2] Direct Testimony of Craig A. Jones, pp. 3-4, 10-11.
[3] *Id.*, p. 19-20.
[4] *Id.*, p. 25, ln. 27 – p. 26, lns. 1-5.

Q. Before turning to your recommended changes, please explain why you support TEP's use of the 4CP AED method to allocate production demand costs.

A. The 4CP AED method recognizes both class energy usage (average demand) and class demand at the time of system peak (through the 4CP) in allocating costs to customer classes. In the case of TEP, the 4CP corresponds to the Company's retail system peak demands in each of the four summer months, when system demand is at its greatest levels. As such, the method accurately captures the requirements that each class makes on the need for investment in generating facilities, and thus reasonably reflects each class's share of costs.

Specifically, the 4CP AED method uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor.[5] This portion of the cost is weighted by the system load factor. The cost of capacity above average demand is then allocated in proportion to each class's <u>excess</u> demand, where excess demand is measured as the *difference* between each class's 4CP demand and its average demand. This portion of the cost is weighted by 1 minus the system load factor. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is assigned to the users who create the need for the additional capacity.

The AED method is described in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC Manual") in its section entitled "Energy Weighting

[5] This concept is discussed in the NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

Methods." This method has the virtue of meeting the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy.[6] As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[7] At the same time, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

The 4CP AED Method is used by APS and UNS Electric, Inc., and is also used by other electric utilities in the neighboring states of New Mexico, Colorado, and Texas.

Q. **Do you also support TEP's use of the 4CP AED method for allocating transmission costs?**

A. Yes. The reasons for using this method to allocate fixed production costs also extend to using it for allocating transmission costs.

Q. **Please discuss your first recommended change to TEP's calculation of the 4CP AED allocation factors.**

A. As I explained above, in the 4CP AED method, system load factor is utilized to determine the proportion of plant cost that is allocated on the basis of average demand (or energy). Load factor is normally calculated by dividing the energy used during a time period by the product of the peak demand during the

[6] Docket Nos. E-01345A-05-0816, et al. Decision No. 69663, pp. 70-71, 154.
[7] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

time period multiplied by the number of hours in the same time period. It thus provides a measure of an entity's actual energy usage relative to its theoretical maximum, given the peak demand of the measured entity (which can be a customer, customer class, or utility system).

TEP does not follow this normal convention in calculating system load factor. Rather than using the retail system peak demand in the denominator of the load factor calculation, TEP averages the retail peak demands of the four coincident peak months. In my view, this approach does not accurately measure system load factor for the test year, and overstates the annual load factor above its true value. Instead, system load factor should be measured by reference to TEP's highest peak demand for that year. This treatment is consistent with the method for measuring system load factor presented in the discussion of the AED method in the NARUC Manual. This measurement is not only the correct measurement of load factor, it is also the most appropriate measurement from a conceptual standpoint given the task at hand.

Q. Please explain this latter point.

A. Recall that the purpose of using system load factor in the 4CP AED method is to identify the proportion of costs to be allocated on the basis of average demand, which in turn is capturing the portion of plant that each class would require if its respective kilowatt-hour usage was consumed at a 100% load factor for the entire year. Consistent with this premise, the calculation of average demand in this exercise is a single annual value. This point is critical to the logic here because excess demand, which is measured using 4CP, only exists as a concept in relation to annual average demand (i.e., it is the excess above average demand). Thus, the load factor weight that is attached to this annual average demand should be measured using the single peak demand (1CP) for the test year. The number of CPs used in calculating excess demand – be it 1, 4, or some other number – is irrelevant to the determination of annual average demand and irrelevant to the determination of system load factor for the test period. There is but one system load factor during the year, not multiple load factors depending on how many CPs are used to calculate excess demand.

In addition to being conceptually correct from the standpoint of cost allocation, measuring load factor with respect to the highest peak demand is consistent with the approach TEP uses in assessing its load and resource balance as documented in the Company's integrated resource plan.[8]

Q. Please discuss your second recommended change to TEP's calculation of the 4CP AED allocation factors.

A. TEP's original calculation of the 4CP AED allocator resulted in a 4CP AED factor for the Lighting class of 0%. This occurred because the Lighting class had no demand during TEP's four coincident peaks, so that class's 4CP demand was less than its average demand, i.e., negative excess demand. This situation often occurs for Lighting customer classes when utilities utilize the 4CP AED method, and it is typically remedied by adjusting the calculation so that the excess demand for each class is no less than zero. My class cost-of-service study calculates the Lighting class's 4CP AED factor using zero excess demand and the class's share of average demand (or energy).

Q. Has TEP addressed the issue regarding the Lighting class's 4CP AED factor?

[8] See TEP 2014 IRP, pp. 28-29.

A. Yes, the Company attempted to address this issue in response to a Staff data request.[9] Apparently, at Staff's request, TEP produced a version of its class cost-of-service study, which I term "TEP's 2nd Revised Model,"[10] incorporating non-coincident peak ("NCP") data in the calculation of its AED allocator. TEP's NCP AED approach produces a Lighting AED factor of slightly greater than 0%. However, under TEP's NCP AED approach, the excess demand component for the Lighting class is still negative. TEP's 2nd Revised Model also suffers from a number of other analytical flaws.

Q. What other analytical flaws in TEP's 2nd Revised Model have you identified?

A. TEP's 2nd Revised Model improperly applies the NCP AED method. Firstly, TEP continues to utilize the 4CP load factor, rather than the single peak demand load factor, to weight the average demand (or energy) component of the AED allocator. Secondly, rather than using each class's single annual NCP in the calculation of the AED allocator, TEP averages the NCP demands that occurred during each of the four coincident peak months. TEP has not formally revised its direct filing or offered any testimony supporting the use of the NCP AED method. I support adoption of the 4CP AED method, incorporating my two corrections described above.

Q. Aside from TEP's method for production demand and transmission cost allocation, do you have any other concerns with the embedded cost-of-service study prepared by TEP?

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[9] TEP's Response to Staff Data Request 20.11, provided in Exhibit KCH-22.
[10] TEP's 2nd Revised Model was produced subsequent to TEP's 1st Revised Model I discuss below.

A. Yes. There are a number of errors and analytical flaws in TEP's original cost-of-service study unrelated to production demand and transmission cost allocation. Two of these errors have been acknowledged by TEP in response to AECC data requests:[11]

(1) TEP inadvertently failed to allocate any Meters or Services costs to the Large General Service ("LGS") class.

(2) TEP allocated customer-related distribution costs based on NCP demand rather than number of customers.

TEP provided a revised class cost-of-service model to AECC ("TEP's 1st Revised Model") on May 6, 2016 that corrects these two errors but has not formally revised its direct filing.

In addition, there are three additional errors and/or analytical flaws that TEP has not acknowledged at this time, to the best of my knowledge. These are:

(3) TEP (seemingly inadvertently) allocates the entirety of Administrative & General ("A&G") expenses based on number of customers.

(4) Despite specifying in its tariff that Large Power Service – Time of Use ("LPS-TOU") customers are to provide their own transformers and are subject to primary service and metering, TEP allocates line transformer costs to the LPS class and provides no cost recognition for LPS primary service.

(5) TEP's study does not allocate any portion of Other Operating Revenues to the proposed High Voltage (138 kV) class.

Q. Please explain the second error acknowledged by TEP, regarding the allocation of customer-related distribution costs.

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[11] TEP's Responses to AECC Data Requests 3.3 and 3.4, provided in Exhibit KCH-22.

A. Certain distribution costs have a significant customer-related component, since distribution facilities are installed to deliver service to customer premises. As such, a considerable portion of the investment required to provide these facilities is directly related to the number of customers and their geographic dispersion on the utility's system. A well-designed and fair distribution cost-of-service study should take these aspects of cost causation into account.

The minimum-size method classifies a portion of certain distribution plant accounts as customer-related based on the minimum size distribution system required to serve each customer. The difference between the total plant investment and the customer-related portion is classified as demand-related. [12]

TEP uses the minimum-size method to determine the customer-related and demand-related portions of certain distribution plant accounts: FERC Accounts 364 (Poles, Towers & Fixtures), 365 (Overhead Conductors & Devices), 366 (Underground Conduit), 367 (Underground Conductors & Devices), and 368 (Line Transformers).[13] However, TEP's original class cost-of-service study allocates the entirety of these accounts to classes based on NCP demand.

TEP's 1st Revised Model properly allocates the customer-related portions of FERC Accounts 364 through 368, and proportionate amounts of related accumulated depreciation, O&M expenses and depreciation expense, based on customer counts. The remaining demand-related portion is allocated based on distribution NCP.

[12] The NARUC Manual describes the minimum-size method on pp. 90-92.
[13] See TEP's Response to AECC Data Request 7.1, attachment AECC 7.1 TEP Min System Study v3 10-21-2015 without HW. The attachment Summary tab is provided in Exhibit KCH-22. TEP classifies FERC Accounts 369 (Services) and 370 (Meters) as 100% customer-related and allocates these costs using a meter cost-weighted customer allocator.

Q. Please explain the third analytical flaw listed above, regarding to the allocation of A&G expenses.

A. Apparently, TEP's study functionalizes A&G expenses based on wages, and classifies A&G expenses into demand-related and customer-related portions based on the various utility functions. However, TEP allocates the entirety of A&G expenses based on number of customers. This has the effect of over-allocating A&G expenses to classes with a relatively high number of customers – the Residential and Lighting classes.

Q. Have you attempted to correct the allocation of A&G expenses?

A. Yes. My class cost-of-service study allocates A&G expenses based on each class's allocated share of O&M expenses excluding A&G, corresponding to TEP's functional separation of A&G expenses. My correction reduces the allocation of A&G expenses to the Residential and Lighting classes.

Q. Please explain the fourth analytical flaw listed above, regarding the allocation of line transformer costs to the LPS-TOU class.

A. TEP's proposed LPS-TOU tariff states, "The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers." This language is consistent with the current LLP-14 and LLP-90 tariffs, which, with the exception of one customer served at 138 kV voltage, are being consolidated into the LPS-TOU tariff. However, TEP allocates line transformer costs to the LPS-TOU class like all other distribution classes, and provides no cost recognition or specific rate discount to LPS-TOU customers to reflect service at primary rather than secondary voltage.

In discovery, TEP contends that, "some level of transformation is appropriately included in the rates for this class," because customers served a variety of voltages were "grandfathered" onto the current LLP tariffs before the referenced language was added to the tariffs.[14]

TEP's class cost-of-service study does not recognize different loss factors for the LPS-TOU class, and does not separately identify and allocate the cost of its secondary distribution system. Ironically, the GS and LGS tariffs include a discount for customers served at primary voltage. However, no such discount is provided for LPS-TOU customers served at primary voltage.

In discovery, TEP indicates that 12 out of 18 LPS customers are served with customer-owned transformers, and 2 of those 12 are served with both customer-owned and TEP-owned transformers.[15] TEP indicates that 9 LPS customers are served at primary voltage, and 8 are served at secondary voltage, while 1 LPS customer is served at both primary and secondary voltage.[16]

Q. Have you corrected this analytical flaw?

A. In part. My class cost-of-service study begins to address this conceptual flaw by excluding the LPS-TOU class from line transformer cost allocation. Since the majority of LPS-TOU customers own their own transformers, and the tariff is designed as such, it would be appropriate to include a small "up-charge" for LPS customers who are instead served by TEP's transformers.

[14] TEP's Responses to AECC Data Request 3.1, provided in Exhibit KCH-22.
[15] TEP's Response to AECC Data Request 15.4, provided in Exhibit KCH-22.
[16] TEP's Response to AECC Data Request 15.2, provided in Exhibit KCH-22.

Regarding further differentiation between primary and secondary LPS customers, TEP claims it does not currently have the necessary billing determinants or load research data available.[17] TEP's line loss study did not develop a primary voltage loss factor.[18] I recommend that the Commission require TEP in its next rate case to separately identify the primary voltage LPS-TOU customer grouping and exclude such customers from secondary distribution cost allocation, as well as determine the primary voltage loss factor and reflect the factor in its cost-of-service analysis.

Q. **Please explain the fifth analytical flaw listed above, regarding the allocation of Other Operating Revenues to the 138 kV class.**

A. TEP allocates FERC Accounts 454 (Rent from Electric Property) and 456 (Other Electric Revenues) to customer classes based on rate base. Other Revenue serves to reduce the sales revenue that would otherwise be required for each rate class to achieve a uniform rate of return. However, TEP fails to allocate any Other Revenue to the proposed High Voltage (138kV) class in Schedule G-2 (Class Cost of Service Study - Summary at Proposed Rates). This error occurs because TEP ties the Other Revenue presented in Schedule G-2 to the Other Revenue presented in Schedule G-1 (Class Cost of Service Study - Summary at Present Rates). TEP does not depict the High Voltage customer as a distinct class in Schedule G-1, and instead includes the High Voltage customer within the LPS class. Thus, the entirety of Other Revenue allocated to the combined LPS class is

[17] TEP's Response to AECC Data Request 8.4, provided in Exhibit KCH-22.
[18] TEP's Response to AECC Data Request 3.2, provided in Exhibit KCH-22.

credited to the non-High Voltage LPS class in Schedule G-2, and no Other Revenue is allocated to the High Voltage class.

Q. Have you corrected this error?

A. Yes. My class cost-of-service study distributes the Other Revenue TEP allocates to the combined LPS class between the non-High Voltage LPS class and the High Voltage class based on rate base.

Q. What revenue requirement change would each class receive at TEP's requested revenue requirement if rates for each class were set at cost-of-service using your corrections to TEP's cost-of-service study?

A. The revenue requirement change for each class at TEP's requested revenue requirement is presented in Tables KCH-1 and KCH-2, below. Table KCH-1 shows the sales revenue change using the PPFAC of $0.00682/kWh that was in effect at the time TEP filed its case, whereas Table KCH-2 shows the sales revenue change using TEP's *current* PPFAC of $0.001501/kWh. I am presenting the revenue changes both ways to allow for comparability to TEP's filed case, while at the same time representing class impacts that would result from setting rates at cost-of-service as accurately as possible. TEP uses the PPFAC of $0.00682/kWh to present the rate impacts from its proposed rate spread in Exhibit CAJ-2. By using the same PPFAC as TEP in Table KCH-1, the current revenues included my Table KCH-2 are comparable to the analysis shown by TEP in Exhibit CAJ-2. But at the same time, it is also important to present this information using the *current* PPFAC, which I do in Table KCH-2, because that depiction more accurately portrays rate impacts relative to current rates.

Table KCH-1
Revenue Change to Achieve Equalized Rate of Return
Using $0.00682/kWh PPFAC

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	Sales Revenue at COS (c)	Sales Revenue Change to Achieve COS $ (d)	Sales Revenue Change to Achieve COS % (e)
Residential	421,989,186	538,426,766	116,437,580	27.6%
General Service	231,608,546	220,346,228	(11,262,319)	-4.9%
Large General Service	152,925,605	125,760,767	(27,164,838)	-17.8%
Large Power Service	[redacted]			
High Voltage 138kV				
Total LPS (TOU & 138kV)	146,480,335	127,244,153	(19,236,182)	-13.1%
Lighting	4,845,334	7,080,876	2,235,542	46.1%
Total Sales Revenue	957,849,006	1,018,858,790	61,009,784	6.4%

Table KCH-2
Revenue Change to Achieve Equalized Rate of Return
Using Current PPFAC

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	Sales Revenue at COS (c)	Sales Revenue Change to Achieve COS $ (d)	Sales Revenue Change to Achieve COS % (e)
Residential	402,568,874	538,426,766	135,857,892	33.7%
General Service	221,889,211	220,346,228	(1,542,984)	-0.7%
Large General Service	145,189,541	125,760,767	(19,428,773)	-13.4%
Large Power Service	[redacted]			
High Voltage 138kV				
Total LPS (TOU & 138kV)	135,770,825	127,244,153	(8,526,672)	-6.3%
Lighting	4,638,212	7,080,876	2,442,664	52.7%
Total	910,056,663	1,018,858,790	108,802,127	12.0%

Q. What observations do you draw from Tables KCH-1 and KCH-2?

A. The Residential and Lighting classes require significant increases to achieve equalized rates of return under TEP's proposed revenue requirement. In contrast, the LGS, High Voltage, LPS, and GS classes require rate decreases to achieve equalized rates of return.

Q. In preparing Table KCH-1 and KCH-2 did you have to make any adjustments to TEP's data?

A. Yes. TEP is proposing to reconfigure its customer classes to a considerable extent. For example, TEP is proposing to create a new Medium General Service rate schedule and a new High Voltage rate schedule, as well as requiring certain customers to migrate between existing classes. However, in presenting its class revenue changes, TEP does not update current revenues to reflect the new composition of the classes. That is, in Schedule H-1, for example, the *proposed* revenues reflect the *new* class composition, while the *current* revenues reflect the *old* (current) class composition, which makes the *change* in revenues presented in Schedule H-1 almost meaningless for several classes. Consequently, the only way to gain insight into class impacts in TEP's filing is to review the rate impact tables presented in Exhibit CAJ-2, but even these entries do not provide a comprehensive depiction of what is occurring at the class level.

In order to avoid this pitfall I have adjusted current revenues in Tables KCH-1 and KCH-2 to reflect TEP's proposed composition of each class. By presenting the information in this way, I hope to make the class impacts shown in the tables more understandable.

REVENUE ALLOCATION

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining revenue allocation, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. How does the spread of rates proposed by TEP relate to class recovery of cost of service?

The revenue allocation proposed by TEP is presented in Table KCH-3, below, alongside current revenues calculated using the current PPFAC rate. The difference between TEP's proposed revenue allocation and cost allocation using my corrected class cost-of-service study represents the subsidy received or paid by the class at TEP's proposed rate spread.

Table KCH-3
TEP's Proposed Revenue Spread
& Resulting Subsidies

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	TEP Proposed $ Change (c)	TEP Proposed % Change (d)	Subsidy Paid/ (Received) at TEP Spread[19] (e)	Subsidy Paid/ (Received) at TEP Spread % of COS[20] (f)
Residential	402,568,874	67,399,985	16.7%	(68,457,908)	-12.7%
General Service	221,889,211	35,290,387	15.9%	36,833,371	16.7%
Large General Service	145,189,541	12,020,623	8.3%	31,449,396	25.0%
Large Power Service	[redacted]				
High Voltage 138kV					
Total LPS (TOU & 138kV)	135,770,825	(7,171,556)	-5.3%	1,355,116	1.1%
Lighting	4,638,212	1,262,689	27.2%	(1,179,975)	-16.7%
Total	910,056,663	108,802,127	12.0%	-	0.0%

As shown in Table KCH-3, the LPS class grouping (LPS-TOU and High Voltage 138kV) is relatively close to cost of service under TEP's proposed rate spread. However, the Residential class receives a large subsidy that is primarily funded by LGS and GS classes and to a lesser extent, the High Voltage class. Indeed, TEP's proposed LGS rates are 25.0% above cost of service and GS rates are 16.7% above cost of service.

Q. Using TEP's requested revenue requirement as a benchmark for comparison purposes, do you recommend any changes to TEP's proposed revenue allocation?

A. Yes. TEP's proposed revenue allocation for the LPS class is reasonably close to its cost of service, but I believe the subsidy being paid by GS, LGS, and High Voltage customers is too great. Therefore, I recommend reducing the GS and LGS revenue allocation such that the rates for each class are no more than

[19] Column (e) equals Column (b) plus Column (c) minus Table KCH-2 Column (c).
[20] Column (f) equals Column (e) divided by Table KCH-2 Column (c).

12.5% above cost of service. I also recommend reducing the High Voltage revenue allocation by [redacted] to move this customer class to its cost of service, and fine-tuning the revenue allocation to LPS to bring this class to its cost of service as well. The sum of these net reductions would be offset with a corresponding increase in the revenue allocation to the Residential class, which would also move this class closer to its cost of service, although a considerable subsidy would still remain in residential rates. My proposed revenue allocation is presented in Table KCH-4, below.

Table KCH-4
AECC/Noble Solutions Proposed Revenue Spread
At TEP's Proposed Revenue Requirement

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	AECC/ Noble Solutions Proposed $ Change (c)	AECC/ Noble Solutions Proposed % Change (d)	Subsidy Paid/ (Received) at AECC Spread[21] (e)	Subsidy Paid/ (Received) at AECC Spread % of COS[22] (f)
Residential	402,568,874	93,774,493	23.3%	(42,083,399)	-7.8%
General Service	221,889,211	26,000,295	11.7%	27,543,278	12.5%
Large General Service	145,189,541	(3,708,677)	-2.6%	15,720,096	12.5%
Large Power Service	[redacted]				
High Voltage 138kV					
Total LPS (TOU & 138kV)	135,770,825	(8,526,672)	-6.3%	-	0.0%
Lighting	4,638,212	1,262,689	27.2%	(1,179,975)	-16.7%
Total	910,056,663	108,802,127	12.0%	-	0.0%

Q. Your revenue requirement recommendation would reduce TEP's requested revenue requirement by $48.587 million. What is your recommended rate spread at that lower revenue requirement?

A. My recommended rate spread at AECC's recommended revenue requirement is derived by scaling back each class's revenue allocation by an equal

[21] Column (e) equals Column (b) plus Column (c) minus Table KCH-2 Column (c).
[22] Column (f) equals Column (e) divided by Table KCH-2 Column (c).

percentage of non-fuel revenues relative to my recommended rate spread at TEP's requested revenue requirement. This revenue allocation is shown in Table KCH-5, below. My rate spread also shows a line entry for a "buy-through reserve" that would fund the generation fixed cost associated with the experimental buy-through program, as discussed in the next section of my testimony. This reserve would come from a portion of the revenue reduction that would otherwise apply to customers in the classes eligible for the buy-through program, which under my proposal would be LGS, LPS, and High Voltage. This reserve fund is shown in the line entry of (7,550,207) in the row entitled "Experimental Rider-14 reserve."

Table KCH-5
AECC/Noble Solutions Recommended Revenue Spread
At AECC's Proposed Revenue Requirement

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	AECC/Noble Solutions Proposed $ Change (c)	AECC/Noble Solutions Proposed % Change (d)
Residential	402,568,874	68,531,433	17.0%
General Service	221,889,211	13,428,994	6.1%
Large General Service	145,189,541	(5,475,802)	-3.8%
Large Power Service	[redacted]		
High Voltage 138kV			
Total LPS (TOU & 138kV)	135,770,825	(9,689,345)	-7.1%
Lighting	4,638,212	948,578	20.5%
Sub-Total	910,056,663	67,743,858	7.4%
Experimental Rider-14 Reserve		(7,550,207)	
Total	910,056,663	60,193,651	6.6%

Q. Do you recommend using the same approach to rate spread and funding the buy-through program if the Commission were to adopt a revenue requirement reduction that is different than the amount of AECC's proposed recommended revenue requirement reduction?

A. Yes. For an alternate revenue requirement, I recommend scaling down (or up as appropriate) each class's revenue allocation by an equal percentage of non-fuel revenues relative to my recommended rate spread at AECC's recommended revenue requirement shown in Table KCH-5, while still providing for the buy-through reserve fund of $7,550,207. As is the case for Table KCH-5, the buy-through reserve would be funded from a portion of the revenue reduction (relative to TEP's filed case) that would otherwise apply to customers in the classes eligible for the buy-through program, which under my proposal would be LGS, LPS, and High Voltage.

Q. What do you recommend in the event that the Commission does not order a revenue requirement reduction relative to TEP's proposed revenue increase that is sufficient to fund the buy-through requirements?

A. In that event, although it appears unlikely, I recommend that the program costs be funded from the classes eligible for the buy-through program using the rate spread approach I am recommending at the approved revenue requirement.

BUY-THROUGH TARIFF

Q. Please provide an overview of the buy-through tariff presented by TEP in this proceeding.

A. TEP has submitted a buy-through tariff in this proceeding pursuant to the settlement agreement approved by the Commission in the proceeding concerning the acquisition of UNS Energy by Fortis, Inc.[23] However, TEP is opposed to the

[23] Docket Nos. E-04230A-14-0011 and E-01933A-14-0011, Settlement Agreement Attachment A, Condition 31, approved by the Commission in Decision No. 74689.

implementation of this tariff, contending it would allow certain large customers to "cherry pick" currently available capacity in the market.[24]

As described in Mr. Jones's Direct Testimony, Experimental Rider-14, Alternative Generation Service, is designed as an optional program to provide an alternative generation arrangement for LPS-TOU and High Voltage customers.

Q. How would this alternative generation arrangement operate?

A. According to Mr. Jones's Direct Testimony, the participating customer would select a wholesale generation service provider with whom to contract to sell power to the Company on the customer's behalf. The power would be delivered to the Company's point(s) of delivery, and the Company would provide transmission and delivery services under the customer's current retail rate schedule.[25]

The Company would purchase and manage this generation for the customer for a management fee of \$0.0040 per kWh.[26] The Company would also serve as the scheduling coordinator and would provide Imbalance Service according to the Company's Open Access Transmission Tariff, with Imbalance Energy based on the generation service provider's portfolio of customer loads. Customers would be charged for Imbalance Service at a rate greater than \$0.00 per kWh, and less than or equal to the rate charged to the generation service provider by TEP. The Company would then bill the customer for the generation

[24] Direct Testimony of Craig A. Jones, pp. 61-62.
[25] *Id.*, p. 62.
[26] *Id.*

service provider's charged amounts for Generation Service and Imbalance Service.[27]

The customer would also be subject to all of the charges and adjustments in its retail rate schedule with the exception of the Base Power Charge and the PPFAC. In addition, the customer would be responsible for the hedging cost associated with the customer's standard generation service at the time the customer takes service under the rider.[28]

Q. Please describe the buy-through program size, eligibility requirements, and program term as designed by TEP.

A. The total program would be limited to 30 MW of peak load, and would be available to customers in the LPS-TOU and High Voltage rate classes with peak demands of 3,000 kW or greater. Eligible customers could apply during the initial enrollment period, and if the total megawatts of peak load from the applications exceed the program maximum, customers would be selected through a lottery process to be developed by TEP.[29] The Company proposes that the program be available for no more than four years from the effective date of new rates in this docket.[30]

Q. What would happen if the generation service provider defaults, or the customer wants to return to standard generation service?

A. If the generation service provider cannot meet its contractual obligations, the customer must notify the Company and select another generation service provider within 60 days. The Company would supply power to the customer prior

[27] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet No. 714-2.
[28] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet Nos. 714-1 through 714-2.
[29] Direct Testimony of Craig A. Jones, p. 63.
[30] *Id.*, p. 62.

to execution of the new power contract at the Dow Jones Electricity Palo Verde Daily Index price plus $20 per MWh.

If the customer wishes to return to standard generation service without providing one year notice to the Company and prior to program termination, the Company would supply power to the customer at the Dow Jones Electricity Palo Verde Daily Index price plus $20 per MWh until the Company is able to integrate the customer back into its generation planning and provide power at standard retail rates.[31]

Q. What is your assessment of the buy-through program presented by TEP?

A. Arizona Revised Statute §40-202(B) declares that "It is the public policy of this State that a competitive market shall exist in the sale of electric generation service."[32] Although the Commission adopted Retail Electric Competition Rules ("Rules") in the furtherance of this policy and commenced implementation, retail competition, also known as direct access service, has been suspended for more than a decade in Arizona. In the meantime, direct access service has been providing benefits to customers in many other states in the country.

Q. Are you aware that several parties involved in TEP's Application for Approval of the Company's 2016 REST Implementation Plan[33], which has been consolidated with this rate proceeding, have opined on the applicability of A.R.S. §40-202(B) to the Commission, and the state of the Rules in general?

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[31] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet No. 714-3.
[32] ARS 40-202(B).
[33] Docket No. 01933A-15-0239.

A. Yes. I understand that the Commission consolidated that application with this rate proceeding for the very specific purpose of determining whether approval of TEP's proposed self-owned residential solar ("TORS") program and Residential Community Solar ("RCS") program is in the public interest, given the rate impacts to customers. I believe it would be inadvisable for the Commission to make any legal determination concerning the applicability of A.R.S. §40-202(B), or the state of the Rules, as a result of the evidentiary hearing intended to focus on the narrow issues surrounding the TORS and RCS programs. AECC will be filing a Reply Brief to address these legal issues.

Q. What is your assessment of the buy-through program presented by TEP?

A. TEP's opposition to the buy-through program is misplaced. Ironically, the Company argues that approval of its TORS and RCS programs is in the public interest because they give customers *more choice*, and a greater opportunity to save money. The same arguments can be made for commercial and industrial customers seeking to manage power costs through market transactions, but TEP has selectively declined to support allowing customers these types of choices.

While I believe it would be preferable to allow Arizona customers full access to the electric power marketplace to take advantage of the benefits of competition as intended by the Arizona Legislature, a buy-through program represents a compromise that provides commercial and industrial customers the opportunity to engage in market transactions and potentially reduce their energy costs, consistent with state policy, but without implementing full direct access service. Moreover, a successful buy-through program will enhance the economic development climate of the TEP service territory and of the state generally.

Given that direct access service is not currently available in Arizona, I recommend adoption of a buy-through program in the TEP service territory as a "second best" option. I recommend adoption of a program that is as similar as reasonably possible to the AG-1 program currently in effect in the APS service territory, but with a different funding mechanism than the APS program. This means adopting some of the features of the buy-through program presented by TEP, but modifying other features to make the program open to a wider variety of customers, thus making it a more viable option. Specifically, I recommend changes to program scale, eligibility, pricing, terms of return to standard generation service, and the mechanics of fixed generation cost recovery. I also recommend a clarification to the program term.

Q. What is your recommended clarification to the program term?

A. I do not disagree with TEP's proposal to target a four-year period for the term of the program. However, I believe it is important for consideration of program extension or modifications to be considered in the context of a future general rate case prior to the termination of the program. Therefore, I recommend that the term of the program be restated to indicate that the buy-through program will continue at least until the start of the first rate-effective period (following a general rate case) occurring no less than four years from the starting date of the buy-through program.

Q. Please describe the change to program scale that you are recommending.

A. I believe that the program cap of 30 MW proposed by TEP is too low. TEP has approximately 30% of the non-residential load that APS has. APS's AG-

1 program is capped at 200 MW. A comparable cap for TEP is around 60 MW, which is what I am recommending.

Q. Please describe the changes to program eligibility that you are recommending.

A. I recommend broadening the range of the customers that would be eligible to participate in the buy-through program. Specifically, I recommend allowing customers to participate with a minimum load size of 3 MW (peak demand), as proposed by TEP, but allowing aggregation of smaller loads in the LGS class owned by the same corporate entity to achieve that 3 MW threshold. Each single site aggregated to reach the 3 MW threshold should have experienced a billing demand of at least 200 kW in the past year to be eligible.

Q. Why do you recommend broadening the range of eligible customers?

A. The APS buy-through program reserved 50% of the initial capacity for customers on Schedule 32-L, which roughly corresponds to the TEP LGS class. The APS program allows Schedule 32-L (and in some cases smaller) customers to aggregate their single site loads to achieve the 10 MW minimum size required to participate in the AG-1 program. Experience with the AG-1 program demonstrates that there is keen interest on the part of commercial and public sector customers to participate in the market for electric power. This opportunity should be available to similarly-situated TEP customers.

Q. You state that the APS AG-1 program allows aggregation but requires a 10 MW minimum aggregated load size. Why are you recommending a 3 MW aggregated load size for TEP?

A. APS has a larger service territory than TEP, so there is greater potential to aggregate smaller loads up to a 10 MW threshold. Indeed, the APS non-residential retail load is about three times the size of TEP's. My recommended 3 MW threshold for aggregated loads in the TEP service territory simply scales back the APS aggregate threshold to take into account the smaller TEP service territory.

Q. Are there aspects of buy-through program pricing proposed by TEP that you agree are reasonable?

A. Yes. TEP's proposal to assign a pro rata share of previously-incurred hedging costs is reasonable in *concept.* I note, however, that the reasonableness of the specific calculations that TEP intends to apply has yet to be demonstrated.

Q. What changes to buy-through program pricing are you recommending?

A. I am recommending changes to the proposed monthly management fee as well as to the continuation of generation capacity charges proposed by TEP.

Q. What change to the monthly management fee are you recommending?

A. TEP is proposing a monthly management fee of $0.004/kWh for buy-through service. While I agree that some management fee is appropriate, I believe the fee proposed by TEP is excessive, as it is more than six times greater than the $0.0006/kWh management fee charged by APS for AG-1 service. In its review of its AG-1 program, APS concluded that a tripling of the management fee would be appropriate if the program is continued.[34] This would correspond to a management fee of $0.0018/kWh. Based on that conclusion, I believe a management fee of $0.002/kWh, or half of what TEP is proposing, is reasonable.

[34] See Docket No. E-01345A-16-0036, Direct Testimony of Leland R. Snook, p. 45.

Q. What changes to TEP's proposed generation charges for buy-through customers are you recommending?

A. Under the TEP program, the unbundled Generation Capacity rate components would continue to apply to 100% of the buy-through customer's billed demand. In other words, in addition to purchasing its generation service from a competitive supplier, the buy-through customer would be required to continue to pay TEP for the fixed cost of generation service that the buy-through customer would be utilizing. This requirement to "pay twice" for fixed generation service obviously undermines the economics of participating in the program; indeed, as TEP is opposed to adoption of the program, this feature appears designed to ensure that the program would fail, even if it was approved. This feature of TEP's proposal is unreasonable, does not have an analogue in the APS AG-1 program and should not be adopted.

Further, the fixed generation charges proposed by TEP are in effect stranded cost charges that are typically levied by utilities when direct access service is being offered. A critical distinction with respect to retail choice programs is that in exchange for the customer's payment of stranded cost charges for a period of time (e.g., five years), the customer is allowed to migrate *permanently* to market participation with no further stranded cost obligation. That is not the case with the proposed buy-through program. When the term of the customer's participation in the buy-through program has expired, the customer is presumed to have no continued right to market procurement unless the program is extended and the customer is able to regain a slot. In short, if the participating customer is required to pay a stranded cost charge as proposed by TEP, then a more permanent shopping option, accompanied by a timetable for cessation of stranded cost obligations, should be available. Moreover, stranded cost recovery for TEP was previously implemented and completed by the terms of the amended Settlement Agreement approved by the Commission in Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.

Rather than the stranded cost charge proposed by TEP, the going-forward charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billing load at the unbundled Generation Capacity rate components for the customer's rate schedule. [35] This pricing approach ties the charge for reserve capacity to TEP's planning reserve margin in the Company's Integrated Resource Plan ("IRP") and is comparable to APS's AG-1 charge for reserve capacity.

Q. What does planning reserve margin refer to and how is it relevant?

A. A planning reserve margin is used in the resource planning process to compensate for uncertainty surrounding future load forecast changes and resource contingencies such as generation or transmission forced outages. The planning reserve margin is calculated as the amount of firm peak resource capacity in excess of projected retail demand as a percentage of total demand. The planning reserve margin used by TEP in the Company's IRP is 15%.[36]

By way of comparison, under the AG-1 tariff, the monthly reserve capacity charge is applied to 15% of the customer's billed demand priced at

[35] As described in the following section my testimony, I recommend that the LPS and 138 kV Delivery energy charges be re-designated as Generation Capacity energy charges. For LPS and 138 kV buy-through customers, I recommend that the reserve capacity charge be applicable to 15% of kWh at the Generation Capacity energy rate and 15% of billing kW at the unbundled Generation Capacity demand charge component.
[36] See TEP 2014 IRP, p. 43 and 2016 Preliminary IRP, p. 33.

APS's cost-based rate for generation capacity filed at FERC, consistent with APS's planning reserve margin of 15%.[37]

Q. If the pricing features proposed by TEP are not adopted, how should the Company's revenue deficiency associated with the buy-through program be recovered?

A. In my discussion of rate spread, above, I recommended that the first $7,550,207 of any revenue requirement reduction apportioned to LGS, LPS, and High Voltage customers be used to support the Experimental Rider-14 buy-through program.

This funding mechanism would work as follows. The first $7,550,207 of revenue requirement reduction apportioned to LGS, LPS, and High Voltage (collectively) would <u>not</u> be applied to a change in rates per se. Rather, this $7,550,207 would be used to absorb TEP's revenue deficiency that is attributed to the reduction in fixed generation revenues from buy-through customers. In this way, TEP is able to recover its approved revenue requirement, and the customer classes not eligible to participate in the program are held harmless from adoption of the buy-through provision.

Q. Why is it reasonable to recover the fixed generation costs from the classes eligible to participate in the program rather than directly assigning the cost recovery to the buy-through participants?

A. As I discussed previously, directly assigning stranded cost charges might be appropriate if participants were being offered a more permanent shopping option. Further, the opportunity to participate in the program provides a potential

[37]See APS 2014 IRP, p. 93.

value-added option for the members of the eligible classes. It strikes me as more reasonable to recover the fixed generation costs of the buy-through program through a foregone rate reduction from the eligible classes rather than levying a 100% stranded cost charge as proposed by TEP.

Q. How did you calculate that the revenue required to fund the buy-through program is approximately $7,550,207 per year?

A. I applied the unbundled Generation Capacity rate components, corrected as discussed in the next section of my testimony, to the load associated with my recommended 60 MW program cap for each of the eligible classes (LGS, LPS, and High Voltage), assuming fully-subscribed participation.[38] I then reduced the resulting amounts by the revenues from the 15% reserve capacity charge I am recommending. The $7,550,207 estimate is the simple average of this calculation applied to the LGS, LPS, and High Voltage rate schedules.[39]

To the extent that program initiation is delayed and does not coincide with the start of the rate-effective period in this case, then there should be a downward adjustment to the annual imputed cost of the program prorated over the planned four-year term of the program, to account for the over-recovery of revenues from eligible classes during the delayed start-up.

Q. What do you recommend if the buy-through program is not fully subscribed?

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[38] To calculate revenue associated with my recommended LPS and 138 kV Generation Capacity energy charges, described in the following section, I estimated the kWh associated with 60 MW of load for LPS and 138 kV.

[39] If all buy-through participants are in the LGS class, the cost would be $8,109,000 per year. Similarly, if all buy-through participants are in LPS class the cost would be $7,006,300 per year and if all buy-through participants are in the High Voltage class the cost would be $7,535,320 per year. My estimate of $7,550,207 is the simple average of this range.

A. If the buy-through program is not fully subscribed, then the revenues set aside to fund the program that turn out to be superfluous should be deferred and returned to the eligible classes through a suitable rate mechanism, perhaps through the PPFAC.

Q. Please explain your proposed change to the Return to Company's Standard Generation Service provision of Experimental Rider-14.

A. If, prior to the end of the planned four-year term of the program, and absent Commission termination of the program, a buy-through customer seeks to return to standard generation service and does not provide one-year's notice, TEP proposes to charge the returning customer the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the customer back into the Company's generation planning. While I agree that this general approach is reasonable, I believe the proposed $20 per MWh mark-up is excessive. By comparison, APS's AG-1 program also requires that an "early" returning buy-through customer pay market rates for up to one year, but without an additional mark-up. I believe the $20 per MWh mark-up proposed by TEP should be eliminated or significantly reduced to no greater than $4 per MWh, to provide some margin to TEP for facilitating this pass-through of market costs.

Q. Are you aware of whether any AG-1 customers have sought to return to APS standard generation service prior to the planned term of the AG-1 program?

A. To the best of my knowledge, no AG-1 customers have sought to return to APS standard generation service prior to the planned term of the AG-1 program.

Q. Do you have any additional comments regarding the role of a buy-through program in the TEP service territory?

A. Yes. TEP steadfastly opposes adoption of a buy-through program yet continues to add generation resources that increase costs for all customers. This rate proceeding includes requested revenue requirement increases for the Gila River plant, Springerville Unit 1, and TEP-owned solar plants. Further, the Company indicates that even with the planned acquisitions of both the 75% interest in Gila River Unit 3 and the 49.5% interest in Springerville Unit 1, as well as the build out of utility scale solar generation resources, the Company was still short 200 MW in peaking capacity in 2015, growing to a deficit of 570 MW in 2018 with the retirement of San Juan Unit 2, according to TEP's 2014 IRP.[40]

In light of these resource needs, rather than opposing the buy-through program, it would make far more sense for TEP to take advantage of customers' interest in acquiring power from the marketplace and use a buy-through program as a planning tool for avoiding the acquisition of generation resources that may be unnecessary if customer purchases of market power were allowed to proceed under a buy-through program.

Finally, TEP has indicated that the Company plans to revise its billing determinants in its rebuttal filing to take account of planned reductions in operations for a major customer. I will respond to that revision in my surrebuttal testimony. I will note at this time that to the extent future loads for this customer are uncertain, it may be useful to consider market options such as buy-through for

[40] See TEP Response to AECC Data Request 16.3.c.

meeting the future service needs of this customer, perhaps even outside the 60 MW cap I am proposing for the buy-through program generally.

Q. Are you aware that APS has proposed to eliminate the AG-1 program in its recent general rate case filing?

A. Yes, I am.

Q. Does APS's proposal to eliminate the AG-1 program impact your recommendations regarding the adoption of a buy-through program in the TEP service territory?

A. No, not at all. I have incorporated APS's observations regarding the AG-1 management fee into my recommendations for TEP. Further, I note that APS's analysis regarding many of the program details indicates that many aspects of the program worked reasonably well.[41] Aspects of the program that may require improvement, such as retail imbalance service, can be addressed as part of discussions among stakeholders in implementing a TEP buy-through program. But most fundamentally, the opposition of utility management and shareholders to allowing Arizona customers to benefit from market pricing is unsurprising and should be given little weight when compared to the declared policy of the State. A buy-through program provides a modest "second best" vehicle to allow customers some of the benefits from competition in generation services, consistent with the State's declared policy.

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[41] APS indicates that program operations such as power scheduling, settlements, information exchanges and billing were generally successful, although improvements could be made to these operations, including more automation. Docket No. E-001345A-16-0036, Exhibit LRS-6DR, p. 2.

UNBUNDLED RATE DESIGN

Q. What aspects of TEP's proposed rate design are you addressing in your testimony?

A. My testimony addresses the rate design for TEP's *unbundled* demand charges for the LGS, LPS, and High Voltage classes. In addition, I address elimination of an energy charge for Delivery service in the rates of demand-billed classes. My absence of comment on other aspects of TEP's rate design should not be interpreted as support for (or opposition to) TEP's proposed rate design generally.

Q. By way of background, please explain the significance of an unbundled tariff.

A. An unbundled tariff is one in which utility rates are separated according to function, in particular, generation, transmission, and distribution (or delivery service). The Commission's rules carefully prescribe the requirements for filing an unbundled tariff.[42] The fundamental requirement in any well-designed unbundled tariff is that each unbundled component should only recover costs associated with its specific function. That is, the unbundled delivery service charge should only recover delivery-services-related costs (and not generation costs), the unbundled generation charge should only recover generation-related costs, and the unbundled transmission charge should only recover transmission-related costs.

A well-designed unbundled tariff is essential to implement a buy-through program because customers in such a program purchase their generation service from third parties and thus the rates they pay the utility must accurately

[42] See AAC R14-2-1606.C.2.

distinguish the avoidable generation costs from the other components in the rate schedule.

As required by Commission rules, TEP's rate schedules show rates both on a bundled and unbundled basis.

Q. What is the appropriate basis for designing unbundled rates?

A. The unbundled rate design should be tied to the class costs by function calculated in the class cost-of-service study. Although class revenues may be above or below full cost of service, the unbundled rates should reflect the underlying functional costs to the nearest extent practicable.

Q. Do you agree with TEP's depiction of the functional components of each class's allocated costs?

A. No. In addition to the analytical flaws affecting class cost allocation discussed in the Cost of Service section of my testimony, TEP's depiction of the functional components that comprise each class's costs is distorted.[43] After costs are allocated to customer classes, TEP breaks these costs into various functions by FERC account for each class, based on the overall functional composition of the FERC account for the system. This is problematic because classes utilize the utility functions to different degrees. For example, the High Voltage class utilizes only a minimal amount of the distribution system related to metering. It is inappropriate to attribute a sizeable amount of the High Voltage intangible plant, general plant, or A&G expenses to the distribution function.

[43] TEP presents these results on the tabs named RES byFunction, GS byFunction, LGS byFunction, LPS byFunction, 138kV byFunction, and LIGHT byFunction in its class cost of service model. I also corrected the depiction of income taxes for the LPS and 138kV classes on their respective Function tabs.

The problem I am describing affects numerous FERC accounts that serve multiple functions and/or are comprised of both demand-related and customer-related costs. These calculations affect the functional unit costs by class, which are the appropriate basis for designing unbundled rates. My cost-of-service study corrects the depiction of each class's functionalized and classified cost components.

Q. Do you have concerns with the rate design of TEP's unbundled tariff?

A. Yes. TEP's unbundled rate design is flawed in that the Company is attempting to recover fixed generation-related costs in the Delivery-related components of the LGS, LPS, and 138 kV rates, contrary to the fundamentals of proper unbundled rate design. For example, TEP's original class cost-of-service study, upon which TEP's filed unbundled rates are based, calculated a per-unit demand production cost of $10.60 per kW for the LGS class. However, TEP's proposed LGS tariff states an unbundled Generation Capacity demand charge component of only $7.95 per kW. Conversely, the unbundled Delivery demand charge component is set above cost. According to TEP's original cost of-service-study, the per-unit distribution demand cost for the LGS class is $3.13 per kW, but TEP proposes an unbundled LGS Delivery demand charge component of $3.86 per kW, in addition to substantial Delivery energy charges for the class.

Q. Why is this a problem?

A. It is a problem because the fundamental economic proposition in a buy-through rate is that the buy-through customer is able to bypass either all, or a significant portion of, the unbundled generation charges. If the utility's unbundled rate design shifts cost recovery from generation charges to distribution (or delivery) charges, then the avoidable generation costs will be underpriced and unavoidable distribution charges will be overpriced. As a result, the ability of customers to shop for buy-through power will be thwarted. Indeed, that is exactly what is likely to occur if TEP's unbundled rate design is accepted.

This situation could significantly undermine the economics of acquiring generation service in the power market. Indeed, shifting generation-related costs into the distribution (or delivery) charge is contrary to the very purpose of unbundling rates. It also appears to be contrary to the requirements of the Rules (AAC R14-2-1606.H.2), which states that rates for unbundled services "shall reflect the costs of providing the services."

Q. Have you calculated alternative unbundled rates for the LGS, LPS, and High Voltage classes?

A. Yes. I have calculated a set of alternative unbundled rates, based on the results of my corrected cost-of-service study and recommended revenue allocation at TEP's proposed revenue requirement. My proposed rate design is presented in Exhibit KCH-20.

Q. As part of your review of the unbundled tariff components, do you have any additional rate design recommendations?

A. Yes. A portion of the Delivery Charges for demand-billed customers is stated as an energy charge. This is not good rate design. The cost of delivery service is exclusively a function of customer-related costs and demand-related costs; consequently, recovery of these costs should occur exclusively through fixed customer charges and demand charges, not energy charges. Consequently, TEP should be required to eliminate its proposed Delivery energy charges for demand-billed classes. My proposed rate design eliminates the Delivery energy charges, while the overall recovery through the unbundled Delivery demand charge component and the Basic Service Charge is proportionate to the underlying Distribution costs.

To avoid too great a change in the overall relationship between total demand and total energy charges in TEP's rate design for the LPS and High Voltage classes, I have retained an energy charge at the same rate proposed by TEP for Delivery service and applied this charge to the recovery of Generation Capacity costs, which reduces the unbundled Generation Capacity demand charge from the rate it would be otherwise.

Q. What is your recommendation to the Commission on this issue?

A. TEP's proposed relationship between delivery demand charges and generation capacity demand charges in its unbundled tariff should be rejected. Instead, I recommend that the unbundled rate design presented in Exhibit KCH-20 should be adopted at TEP's proposed revenue requirement. To the extent that the revenue requirement for the LGS, LPS, and/or High Voltage classes is reduced from the levels assumed in Exhibit KCH-20, then the unbundled delivery charges and generation charges (excluding power supply) for any class should be reduced pro rata from the charges presented in Exhibit KCH-20 to reflect the reduced revenue requirement.

MOBILE HOME PARK RATE SCHEDULE

Q. What issue are you addressing regarding the rate schedule applicable to mobile home parks?

A. TEP has a special rate schedule applicable to mobile home parks that are master metered, called Mobile Home Park Electric Service – GS-11F. However, this rate schedule does not allow any "new" customers to join, including *existing* master-metered mobile home parks that happen to be on rate schedules other than the mobile home park rate. This restriction preventing existing mobile home parks from switching to this rate schedule is unjust and unreasonable and should be removed from the TEP tariff.

In this general rate case, TEP is changing the name of rate schedule GS-11F to "Mobile Home Park Electric Service (GS-M-F)." However, the rate schedule as proposed continues to include restrictive language that states it is "only available to premises *historically* served on a master metered mobile home park tariff" and that is it is "not available to new facilities." [Emphasis added]. The restrictions in the new language are also unreasonable and should be removed.

Q. Please explain why the restrictions on migrating to this rate schedule should be removed.

A. Mobile home parks that are master metered are generally billed by TEP at a single meter for the entire mobile home park load. The mobile home park operator then delivers the power to its individual residents over its own distribution system and, if sub-metered, bills the residents for their respective usage based on meters attached to each residence.

Significantly, the bills that mobile home park operators pass through to their residents are governed by state statute. Specifically, Arizona Revised Statute § 33-1413.01 provides that master-metered mobile home parks that are sub-metered must not charge their residents more than the utility's prevailing rates for basic single family *residential* service. Because of this statute, it is important that there be a reasonable nexus between what TEP charges a master-metered mobile home park for power and what TEP charges a residential customer for power, because the mobile home park operator can only pass on the latter charges to its residents. If the average rates charged to master-metered mobile home parks are greater than the rates charged to residential customers, then the mobile home park operator will be unfairly harmed by being forced by the TEP tariff to purchase power from TEP at one rate and then required by state statute to resell it at a lower rate. Such a situation would be unreasonable on its face.

Q. Is the situation you are describing an actual problem or simply a hypothetical problem?

A. This situation is an *actual* problem. Master-metered mobile home parks that, for whatever reason, are not served under the mobile home park rate are forced to take service under rate schedules that have no nexus to residential rates. I know of at least one master-metered mobile home park that is taking service under the LGS-13 rate schedule. This rate schedule, unlike current residential rates – and unlike the mobile home park rate – has a very substantial demand charge. While the LGS-13 demand charge may be reasonable for the vast majority of customers taking service under that rate schedule, it is <u>not</u> reasonable for a customer who must resell its power at residential rates. The rate design mismatch between LGS-13 and residential rates is causing an undue penalty assessed on mobile home park operators who must resell power to residents at rates that are below the rates that the operator pays TEP.

I have illustrated this problem for a hypothetical mobile home park taking service on LGS-13. This analysis is presented in Exhibit KCH-21. The example assumes that the mobile home park has the average size and load factor of a mobile home park taking service under the mobile home park rate. The analysis shows that the average cost of service under the LGS-13 rate is 18.66 cents per kWh at current rates, whereas the average rate for residential service under the TE-R-01 rate schedule is 13.06 cents per kWh. If this customer were allowed to switch to the mobile home park rate, the costs would be much closer to the residential rate. However, the current and proposed TEP tariff forbids this customer from switching to the mobile home park rate. This prohibition is unjust, unreasonable, unduly discriminatory, and not in the public interest. Accordingly, this prohibition should be eliminated by the Commission.

Q. Does TEP have an explanation for the restrictions on the availability of the mobile home park rates in its tariff?

A. Yes. TEP cites to the Arizona Administrative Rules, which state, in relevant part:

R14-2-205. Master Metering

A. Mobile home parks -- new construction/expansion

1. A utility shall refuse service to all new construction or expansion of existing permanent residential mobile home parks unless the construction or expansion is individually metered by the utility. Line extensions and service connections to serve such expansion shall be governed by the line extension and service connection tariff of the appropriate utility.

TEP indicates that its restrictions are intended to avoid master-metered circumstances in the future.[44]

Q. Do you believe that TEP's existing or proposed restrictions on this rate schedule are a reasonable means for avoiding master metering in the future?

A. No. R14-2-205 already precludes new master metering in the future for mobile home parks *by requiring utilities to refuse service* to such new facilities. By the same token, if a master-metered mobile home park is already being served by TEP, it must be presumed to be an older facility that predates the prohibition on new master metering. If such a customer happens to be on the wrong rate schedule, no public interest is served in preventing this customer from switching to the mobile home park rate schedule intended for such customers.

Q. What is your specific recommendation to the Commission regarding the mobile home park rate schedule?

A. The applicability criteria for Mobile Home Park Electric Service – GS-11F should be amended to remove the restriction on service to new customers. Similarly, to the extent that TEP's proposed replacement rate schedule GS-M-F is adopted, the prohibition on "new facilities" should be removed, as it is superfluous and ambiguous. Further, the applicability criteria should be amended to remove any language that restricts this rate schedule to premises that have been *historically* served on a master metered mobile home park tariff, as this restriction unreasonably prevents an otherwise eligible customer from switching to this rate schedule from a rate schedule that is ill-suited for the customer. *At a minimum,*

[44] TEP Response to AECC Data Request 21.1(b), provided in Exhibit KCH-22.

the applicability criteria should be amended such that there is no restriction on migrating to this rate schedule for any existing master-metered mobile home park.

Q. Do you have any recommended guidance regarding this rate schedule as it pertains to its future rate design?

A. Yes. Care should be taken to ensure a reasonable going-forward nexus between the mobile home park rate and residential rates. For example, if residential rates are not subject to mandatory demand charges, then neither should the mobile home park rate be subject to them. The statutory restrictions on the rates at which master-metered mobile home parks must resell power require that TEP and the Commission be mindful of the relationship between the mobile home park rate and residential rates going forward.

LOST FIXED COST RECOVERY MECHANISM

Q. What is the LFCR mechanism?

A. The LFCR is an adjustor mechanism that allows TEP to recover certain revenues deemed to be "lost" due to energy efficiency ("EE") and distributed generation ("DG") programs. TEP proposed the LFCR in the last general rate case. The TEP proposal in that case was opposed by many parties, including AECC; however, a compromise was reached and a version of the LFCR was included in the 2013 Settlement Agreement that was approved by the Commission. Now, in this case, TEP proposes changes that would tilt the compromise negotiated in the last case further in the direction of the Company's initial proposal.

Q. What significant modifications to the LFCR mechanism is TEP proposing?

A. The LFCR mechanism is currently designed to permit recovery of a portion of transmission and distribution costs not recovered through base rates due to EE and DG savings. Currently, 50% of demand charge base rate revenue is excluded from the calculation of the LFCR mechanism, as is the entirety of generation-related revenue, purchased power and fuel costs, and customer charge revenue.[45]

As explained in the Mr. Jones's direct testimony, the Company is proposing to expand the costs eligible for recovery though the LFCR mechanism to include generation and fixed must-run fixed costs, as well as the remaining 50% of demand charge revenue currently excluded from the calculation.[46] Further, TEP proposes to increase the year-over-year cap from 1% to 2% due to the proposed expansion of LFCR-eligible costs.[47]

Q. Do you support TEP's proposed changes?

A. No. The LFCR mechanism adopted in the last general rate case was the product of difficult negotiations. I am not persuaded that an LFCR is needed in the first instance, and I particularly disagree with levying this charge on LGS customers, as a significant part of TEP's concern regarding these customers can be addressed through rate design. Therefore, not only do I disagree with TEP's proposed changes, but I also recommend that LGS customers be exempt from this charge going forward.

Q. Please explain how concerns about fixed cost recovery for larger customers can be addressed through rate design.

[45] LFCR Mechanism Plan of Administration.
[46] Direct Testimony of Craig A. Jones, pp. 77-79.
[47] *Id.* pp. 79-80.

A. The premise for recovery of "lost margins" is to insulate the utility from the loss of fixed-cost recovery when customers conserve energy by participating in utility-sponsored energy efficiency programs. This erosion of fixed-cost recovery may occur because, for many rate schedules, a portion of fixed cost is recovered through the volumetric energy charge. Thus, if energy consumption declines, all other things being equal, fixed cost recovery from conserving customers on these rate schedules declines. This problem can be mitigated by recovering a greater proportion of fixed costs through the customer charge and demand charge. Indeed, TEP is proposing to increase both of these charges for LGS. For example, TEP is proposing to increase the LGS customer charge to $1,000 per month, a relatively high customer charge for customers of this size.[48]

Q. Doesn't energy conservation also enable a customer to reduce its billing demand?

A. Yes, but it is much more difficult for a customer to reduce its billing demand from conservation in the short term than its energy usage. This is particularly true given the structure of TEP's tariff, because the billing demand for LGS customers is subject to a 75% ratchet. This ratchet means that the billing demand in any given month cannot fall below 75% of the customer's greatest demand measured during the preceding eleven months – even if subsequent usage is reduced.

Q. How can TEP address fixed-cost recovery concerns through rate design?

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[48] Currently the LGS-13 customer charge is $775 per month and the LGS-85 customer charge is $950 per month.

A. When TEP first requested the LFCR, the stated purpose was to recover delivery service costs that would otherwise be unrecovered when energy conservation or distributed generation occurs.[49] TEP's rates are unbundled; therefore, delivery service rates are already separately stated in the tariff. TEP's proposed delivery service rates consist of customer charges, demand charges, and energy charges. This structure should be changed. As I discussed in my testimony on unbundled rate design, the delivery service energy charges should be eliminated and TEP should recover all of its delivery service costs from demand-billed customers through the customer and demand charges. This rate design change would not only address fixed-cost recovery concerns, it would improve rate design. It is well understood that the cost of providing delivery service is driven by customer-related costs and demand-related costs – not energy-related costs. For this reason alone, TEP's delivery service charges should not have an energy-charge component for demand-billed customers.

Q. If LGS is excluded from the LFCR would other customers be forced to bear the LFCR-related costs "caused" by the larger customers?

A. Absolutely not. If a customer group is excluded from the LFCR mechanism, they would neither pay the LFCR *nor shift costs to other classes for recovery.* The only LFCR costs that should be recorded by TEP would be those directly attributable to the participating classes. Consequently, no costs would be shifted from non-participants to participants.

Q. Please summarize your recommendations concerning the LFCR.

[49] Docket No. E-01933A-12-0291, Direct Testimony of David G. Hutchens, p. 9.

A. TEP's proposals to expand the scope of the LFCR should be rejected. The limitations on the scope of this charge were critical to allowing the LFCR to be included in the 2013 Settlement Agreement approved by the Commission. Further, it is unnecessary and unreasonable for LGS customers to be included in the LFCR program, as concerns about fixed cost recovery from this customer class can be addressed through rate design.

PPFAC RATE DESIGN

Q. What PPFAC rate design issues are you addressing?

A. I am addressing TEP's proposal to modify the rate design of the PPFAC to a percentage adjustment rather than a kWh adjustment and to make this change monthly, rather than annually. I addressed revenue requirement issues concerning the PPFAC separately in my revenue requirement testimony.

Q. Please describe TEP's proposed rate design change for the PPFAC.

A. The PPFAC rate is currently adjusted annually and charged to customers on a per-kWh basis. TEP is proposing to adjust the PPFAC monthly using a twelve-month rolling average and to allocate the PPFAC costs on a percentage of the average base fuel rate as established in a general rate case. The monthly PPFAC charge is proposed to be a single percentage adjustment applied to all base fuel rates for all customer classes.[50]

Q. What reasons does TEP offer for these changes?

A. TEP suggests that a monthly reset of the PPFAC using a rolling twelve month average, combined with hedging, would make changes in the adjustor less

[50] Direct Testimony of Craig A. Jones, p. 77. See also Direct Testimony of Michael Sheehan, p. 42.

volatile.[51] TEP also indicates that changing to a single percentage adjustment better aligns the changes in fuel costs with each rate class's base fuel costs.

Q. What is your assessment of these proposals?

A. TEP's proposal to use a single percentage adjustment for the PPFAC is reasonable as the adjustment would be proportionate to each customer class's fuel costs. I support adoption of this change.

TEP's proposal to change to a monthly reset of the PPFAC creates rate uncertainty from month to month and is potentially problematic. Although I am disinclined to support this change on a standalone basis, I would not oppose this approach if it were adopted as a package in tandem with the 70/30 PPFAC risk sharing mechanism that I am recommending in my revenue requirement testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[51] Direct Testimony of Michael Sheehan, p. 43.

EXHIBIT KCH-20

AECC/Noble Solutions Recommended Unbundled LPS-TOU & 138kV Rates at AECC/Noble Solutions Rate Spread & TEP Requested Revenue Requirement

Line No.	Description	TEP LPS-TOU Proposed[1]	AECC/ Noble Solutions LPS-TOU Recommended	TEP LPS-138kV Proposed[1]	AECC/ Noble Solutions LPS-138kV Recommended
	(a)	(b)	(c)	(d)	(e)
1	Basic Service Charge Components ($/Cust./Mo.):				
2	Meter Services	$77.26	$486.04	$115.88	$336.51
3	Meter Reading	$0.78	$8.13	$1.18	$74.32
4	Billing & Collection	$12.59	$148.61	$18.88	$1,111.62
5	Customer Delivery	$1,909.37	$1,357.22	$2,864.06	$1,477.55
6	Total	$2,000.00	$2,000.00	$3,000.00	$3,000.00
7	Demand Charge Components ($/kW):				
8	Local Delivery (See Note 2)				
9	Summer On-Peak	$2.73	$3.26	$1.86	$0.02
10	Summer Off-Peak	$1.40	$3.26	$0.15	$0.02
11	Winter On-Peak	$1.41	$3.26	$0.56	$0.02
12	Winter Off-Peak	$0.40	$3.26	$0.40	$0.02
13	Generation Capacity				
14	Summer On-Peak	$9.68	$9.21	$9.70	$9.06
15	Summer Off-Peak	$5.50	$3.61	$6.75	$5.07
16	Winter On-Peak	$8.00	$6.16	$8.00	$6.50
17	Winter Off-Peak	$4.00	$1.07	$4.00	$2.93
18	Fixed Must-Run	$1.30	$1.46	$1.30	$1.54
19	Transmission Components (See Note 3):				
20	FERC Transmission Rate	$3.34	$3.39	$3.34	$3.19
21	Ancillary 1: System Control & Dispatch	$0.05	$0.05	$0.05	$0.04
22	Ancillary 2: Reactive Supply & Voltage Control	$0.18	$0.18	$0.18	$0.17
23	Ancillary 3: Regulatory & Freq Response	$0.17	$0.18	$0.17	$0.16
24	Ancillary 4: Spinning Reserve Service	$0.47	$0.48	$0.47	$0.45
25	Ancillary 5: Supplemental Reserve Service	$0.08	$0.08	$0.08	$0.07
26	Total Transmission	$4.29	$4.36	$4.29	$4.08
27	Total Demand Charges ($/kW):				
28	Summer On-Peak	$18.00	$18.29	$17.15	$14.70
29	Summer Off-Peak	$12.49	$12.69	$12.49	$10.71
30	Winter On-Peak	$15.00	$15.24	$14.15	$12.14
31	Winter Off-Peak	$9.99	$10.15	$9.99	$8.57
32	Energy Charge Components ($/kWh):	Delivery	Generation	Delivery	Generation
33	Summer On-Peak	$0.00710	$0.00710	$0.00710	$0.00710
34	Summer Off-Peak	$0.00710	$0.00710	$0.00710	$0.00710
35	Winter On-Peak	$0.00710	$0.00710	$0.00710	$0.00710
36	Winter Off-Peak	$0.00710	$0.00710	$0.00710	$0.00710
37	Power Supply Charges:				
38	Base Power Supply Charges ($/kWh)				
39	Base Power Supply Summer On-Peak ($/kWh)	$0.057760	$0.057760	$0.056544	$0.056544
40	Base Power Supply Summer Off-Peak ($/kWh)	$0.024415	$0.024415	$0.023901	$0.023901
41	Base Power Supply Winter On-Peak ($/kWh)	$0.053200	$0.053200	$0.052080	$0.052080
42	Base Power Supply Winter Off-Peak ($/kWh)	$0.020995	$0.020995	$0.020553	$0.020553
43	PPFAC (%) (See Rider-1 for current Rate)	Varies	Varies	Varies	Varies

Notes:
1. Data Source: Exhibit CAJ-3, pages 301 - 301-3; 302 - 302-3.

2. AECC/Noble Solutions Unbundled Delivery demand charge is designed such that the combination of Basic Service Charge and Delivery demand charge revenues are proportionate to Distribution costs. AECC/Noble Solutions calculated a flat per-kW Distribution rate for each TOU period and eliminated the Delivery energy charges (re-designated as Generation energy charges).

3. AECC/Noble Solutions utilized TEP's general approach to calculating the unbundled Transmission component, based on the 2015 TEP Transmission Expense Workpaper. However, AECC calculated the LPS and 138 kV Transmission components separately.

AECC/Noble Solutions Recommended Unbundled LGS Rates
at AECC/Noble Solutions Rate Spread & TEP Requested Revenue Requirement

Line No.	Description	TEP Proposed[1]	AECC/ Noble Solutions Recommended
	(a)	(b)	(c)
1	Basic Service Charge Components ($/Cust./Mo.):		
2	Meter Services	$38.63	$165.17
3	Meter Reading	$0.39	$2.72
4	Billing & Collection	$6.29	$51.13
5	Customer Delivery	$954.69	$780.98
6	Total	$1,000.00	$1,000.00
7	Demand Charge Components ($/kW):		
8	Delivery Charge (See Note 2)	$3.86	$1.93
9	Generation Capacity	$7.95	$13.25
10	Fixed Must-Run	$1.33	$1.66
11	Total Transmission (See Note 3)	$4.36	$4.36
12	Total Demand Charge	$17.50	$21.20
13	Transmission Charge Components ($/kW):		
14	FERC Transmission Rate	$3.39	$3.39
15	Ancillary 1: System Control & Dispatch	$0.05	$0.05
16	Ancillary 2: Reactive Supply & Voltage Control	$0.18	$0.18
17	Ancillary 3: Regulatory & Freq Response	$0.18	$0.18
18	Ancillary 4: Spinning Reserve Service	$0.48	$0.48
19	Ancillary 5: Supplemental Reserve Service	$0.08	$0.08
20	Energy Charge Components ($/kWh):		
21	Local Delivery - Summer	$0.02510	$0.00000
22	Local Delivery - Winter	$0.01780	$0.00000
23	Base Power Supply Charges ($/kWh):		
24	Base Power Supply Summer	$0.037325	$0.037325
25	Base Power Supply Winter	$0.033801	$0.033801

Notes:

1. Data Source: Exhibit CAJ-3, pages 220 - 220-2.

2. AECC/Noble Solutions Unbundled Delivery demand charge is designed such that the combination of Basic Service Charge and Delivery demand charge revenues are proportionate to Distribution costs.

3. AECC/Noble Solutions utilized TEP's approach to calculating the LGS unbundled Transmission component.

Functional Cost Alignment of AECC/Noble Solutions Proposed Unbundled Rates at AECC/Noble Solutions Rate Spread & TEP Requested Revenue Requirement Combined LPS-TOU and 138 kV Classes

Line No.	Description	LPS-TOU & 138 kV Total Costs [1]	Proportion of Total Gen. & Dist. Costs	LPS-TOU & 138 kV Revenue from AECC/Noble Solutions Recommended Rates	Proportion of Total Gen. & Dist. Revenue [2]
	(a)	(b)	(c)	(d)	(e)
1	Distribution (Demand and Customer)	$9,412,375	16.0%	$8,635,275	15.9%
2	Generation Capacity [3]	$43,863,092	74.6%	$40,450,858	74.7%
3	Fixed Must-Run	$5,494,874	9.3%	$5,065,211	9.4%
4	Total Distribution & Generation Costs	$58,770,342	100.0%	$54,151,345	100.0%
5	Transmission [4]	$12,295,982		$14,649,224	
6	Power Supply	$58,436,997		$58,436,997	
7	Total - All Functions	$129,503,320		$127,237,566	
8	Other Revenue Credit	-$2,259,167			
9	Net Cost to be Collected from Sales Revenue [5]	$127,244,153			

Notes:
1. Based on AECC/Noble Solutions corrected class cost-of-service study at TEP's proposed revenue requirement.
2. Differences between Col. (c) and Col. (e) are due to rate rounding.
3. Power Factor revenues, as well as AECC/Noble Solutions Generation energy charge of $0.0071/kWh, are considered Generation Capacity-related.
4. AECC/Noble Solutions utilized TEP's general approach to calculating the unbundled Transmission rate component.
5. The difference between the net cost to be collected from sales revenue and the Total - All Functions revenue is due to rate rounding.

EXHIBIT KCH-21

Mobile Home Park Illustrative Rate Comparison

Comparison of Average Residential Rates and Rates Paid by a Hypothetical Mobile Home Customer on Rate Schedule LGS-13

TEP Residential Rate Schedule	Current TE-R-01 Rates	TE-R-01 Service Billing Determinants	Revenues
Residential Service (TE-R-01)			
Basic Service Charge Single Phase Per Mo.	$10.00	4,175,628	$41,756,280
Basic Service Charge Three Phase Per Mo.	$15.00	3,442	$51,624
Sum First 500 kWh	$0.05620	762,703,189	$42,863,919
Sum 501-1,000 kWh	$0.06720	503,607,184	$33,842,403
Sum 1,001-3,500 kWh	$0.07980	518,920,086	$41,409,823
Sum>3,500 kWh	$0.08820	16,585,028	$1,462,799
Win First 500 kWh	$0.05620	929,496,499	$52,237,703
Win 501-1,000 kWh	$0.06520	367,506,796	$23,961,443
Win 1,001-3,500 kWh	$0.07810	177,513,099	$13,863,773
Win>3,500 kWh	$0.08710	4,632,713	$403,509
Miscellaneous Revenue			(45,552)
Subtotal Delivery Revenue			$251,807,725
Base Power Summer kWh	$0.035111	1,801,815,486	$63,263,544
Base Power Winter kWh	$0.031532	1,479,149,108	46,640,530
PPFAC Revenue	$0.003892	3,280,964,594	12,770,210
Subtotal Fuel Revenue			$122,674,283
Surcharges			
LFCR	0.8565%		$3,207,438
LFCR	0.2770%		$1,037,315
ECA	$0.000250		$820,241
REST	$0.013000		$42,652,540
DSM	$0.001916		$6,286,328
Subtotal Surcharges:			$54,003,863
Total Estimated Revenues:			$428,485,871
Average $ per kWh:			$0.1306

Hypothetical Mobile Home GS-11F Customer	Current Rates TE-LGS-13 Rates	GS-11F Service Billing Determinants	Revenues
Large General Service (TE-LGS-13)			
Basic Service Charge Per Month	$775.00	12	$9,300
Demand Charge Per kW	$15.25	625	$9,531
Summer kWh	$0.01920	77,430	$1,487
Winter kWh	$0.01340	84,581	$1,133
Subtotal Delivery Revenue			$21,451
Base Power Summer kWh	$0.035111	77,430	$2,719
Base Power Winter kWh	$0.031532	84,581	2,667
PPFAC Revenue	$0.003892	162,011	631
Subtotal Fuel Revenue			$6,016
Surcharges			
LFCR	0.8565%		$235
LFCR	0.2770%		$76
ECA	$0.000250		$41
REST	$0.013000		$2,106
DSM	$0.001916		$310
Subtotal Surcharges:			$2,768
Total Estimated Revenues:			$30,236
Average $ per kWh:			$0.1866

Data Sources:
1. Schedule H-5, Page 1, Bill Count
2. 2015 TEP Revenue Proof - Public

EXHIBIT KCH-22

Exhibit KCH-22

TEP's Responses to Parties' Data Requests Referenced in Testimony

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 09, 2016

AECC 3.1

Please refer to 2015 TEP Schedule G – COSS Competitively Sensitive Confidential, tabs Schedule G-3 and Schedule G-4. Please explain why Large Power Service customers are allocated line transformers costs (Accounts 368 and 595) in TEP's COSS, although the LLP-90 tariff indicates that, "The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load." Are LLP-90 customers otherwise credited for providing their own transformers? Please explain.

RESPONSE:

Most of TEP's LLP customers take service at voltage levels of 138,000 V and less. Since most of the LLP customers were grandfathered onto these LLP rates before the referenced language was added to the tariff, many of the existing customers are taking service at a variety of voltages. The tariff is written to address new customers that will be connected directly to a 13,800 V or 46,000 V system. Therefore, since the class will have a blending of new and old customers, some level of transformation is appropriately included in the rates for this class. As new customers are added and the embedded costs depreciate, this piece will contribute less to the rates for the class as a whole.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 09, 2016

AECC 3.2

Please refer 2015 TEP Schedule G – COSS Competitively Sensitive Confidential, the "Load Data" tab.

a. Please explain why TEP is applying the same loss factors to LPS load as Residential load, although, according to the LLP-90 tariff, LLP-90 is designated as Primary Service with a delivery voltage of not less than 13,800 volts. Does TEP contend that the same level of energy and demand losses (per kWh and kW) are incurred to serve customers at 13,800 volts and residential service voltage? Please explain.

b. Please explain why TEP is applying the same loss factors to energy and demand. Does TEP contend that energy and demand line loss percentages are the same? Please explain.

c. Please provide the line loss study that is the source of the Distribution loss factor of 7.14% and the Transmission loss factor of 5.62%.

d. Does TEP's line loss study indicate the loss factor(s) attributable to the Primary voltage distribution system? If so, please provide the Primary voltage energy and demand loss factors.

RESPONSE:

a. The current "grandfathered" customers receive service at a variety of voltages including secondary voltage. The current tariff language applies to any added load and requires that the customer be served at primary voltage. Nearly all of TEP's LPS customers were on the TEP system prior to the referenced language being included in the tariff. Therefore, the Company has applied its Distribution loss factor to the LPS Class

b.-d. The development of the factors used in this case are explained in the file LineLossMethodSummary.docx filed in support to Schedules G&H (see UDR 1.001). The current study did not provide different factors for energy and demand. The file 2015 TEP Line_Loss_Summary Confidential.xlsx (see UDR 1.001), which provides the details of the study completed, was provided under the proper confidentiality agreements. The filed study considers transmission losses at 345 kV and distribution at TEP's 138 kV system.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 3.3

Please refer to 2015 TEP Schedule G – COSS Competitively Sensitive Confidential, tabs Schedule G-3 and Schedule G-4. Please explain why Large General Service customers are not allocated any Meters or Services costs (Accounts 369, 370, 586, 587, and 597).

RESPONSE:

The Company had not intended to exclude Metering and Service cost from the Large General Service class. The results for this correction are shown below. The Company will be filing a new Schedule G with this correction.

DESCRIPTION	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE POWER SERVICE	138kV	LIGHTING
CORRECTION							
RATE OF RETURN ON RATE BASE[1]	5.52%	-1.58%	19.22%	4.52%	13.38%		-15.82%
(ORIGINAL COST RATE BASE)							
RETURN AT PRESENT RATES	$116,218,763	($17,985,962)	$93,883,970	$10,945,808	$30,438,666	$0	($1,063,719)
FILED POSITION							
RATE OF RETURN ON RATE BASE[1]	5.52%	-1.60%	19.35%	4.61%	13.37%		-15.82%
	(ORIGINAL COST RATE BASE)						
RETURN AT PRESENT RATES	$116,218,763	($18,328,443)	$94,083,779	$11,097,150	$30,429,996	$0	($1,063,719)

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 09, 2016

AECC 3.4

Please refer to the Direct Testimony of Craig Jones, page 21, lines 26-27, which states, "For distribution plant costs found in FERC Account Nos. 364 - 374 either all or a portion of the costs are customer related because they are caused by customers." Please explain why TEP's CCOSS, 2015 TEP Schedule G – COSS Competitively Sensitive Confidential, has allocated the entirety of Accounts 364 through 368 to customer classes based on NCP, despite classifying a portion of these accounts as customer-related. That is, please explain why TEP believes it is appropriate to allocate the customer-related portions of these accounts based on NCP rather than the number of customers.

RESPONSE:

After review of this question, the Company agrees with this change and would like to extend its review to identify all impacts. A new study with this change will be provided as soon as possible.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 7.1

Please refer to TEP's response to AECC Data Request 4.04.

a. Does the TEP Marginal Cost Study 10-30-2015 Competitively Sensitive Confidential.xlsx file constitute the Minimum System Study that was used to derive the customer-related percentages on the "Cust%" tab of the 2015 TEP Schedule G - COSS Competitively Sensitive Confidential file?

b. If the answer to part (a) is affirmative, please provide a workpaper in Excel format demonstrating how these customer-related percentages are derived from data in the TEP Marginal Cost Study 10-30-2015 Competitively Sensitive Confidential.xlsx file.

c. If the answer to part (a) is negative, please provide the Minimum System Study, including all related workpapers in Excel format, and provide the derivation of the customer-related percentages from data in the Minimum System Study in Excel format.

RESPONSE: April 4, 2016

a. Yes

b. **REVISED: THE FILE LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT IS ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.**

REVISED TO LABEL FILE COMPETITIVELY SENSITIVE CONFIDENTIAL: Please see AECC 7.1 TEP Min System Study v3 10-21-2015-Comp-Sen-Conf.pdf, Bates Nos. TEP\021433-021452.

c. N/A

RESPONDENT:

Brenda Pries (a,c) / Edwin Overcast (b)

WITNESS:

Edwin Overcast

RESPONSE: May 9, 2016

b. Please see AECC 7.1 TEP Min System Study v3 10-21-2015 without HW.xlsx for a non-confidential version of the provided file in Excel format. The proprietary information of Black & Veatch has been eliminated in this version. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Brenda Pries (a,c) / Edwin Overcast (b)

WITNESS:

Edwin Overcast

Tucson Electric Power
Minimum System Study (Oct 2015)
Summary

Row No.	FERC A/C A	Description B	Count C	Installed Cost D	Weighted HW Index E	2015 Cost F	Minimum Unit Cost G	Minimum System Cost H	Customer Ratio I
1	364	Poles, Towers & Fixtures	78,094	$ 129,782,729	2.05	$ 266,620,563	$2,172.59	$ 169,666,243	63.64%
2	365	Overhead Conductors & Devices	30,010,103	$ 180,425,882	2.46	$ 444,194,749	$3.00	$ 90,009,711	20.26%
3	366	Underground Conduit							100.00%
4	367	Underground Conductors & Devices	37,435,254	$ 302,831,236	2.30	$ 697,504,479	$7.61	$ 284,871,651	40.84%
5	368	Line Transformers	83,198	$ 263,885,332	3.34	$ 880,186,632	$2,547.89	$ 211,979,352	24.08%

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 April 12, 2016

AECC 8.4

For each of the six customer classes in TEP's class cost of service study, please provide the following information, in Excel format. Please estimate if necessary.

a. The number of customers served at secondary, primary, and 138 kV voltage, based on adjusted test year billing determinants.

b. The kWh sales at meter delivered at secondary, primary, and 138 kV voltage, based on adjusted test year billing determinants.

c. For demand-billed classes, the adjusted test year kW billing determinants served at secondary, primary, and 138 kV voltage.

d. The average test year 4CP demand at meter served at secondary, primary, and 138 kV voltage.

e. The test year 1NCP demand at meter served at secondary, primary, and 138 kV voltage.

RESPONSE:

a. The table below are the number of bills by rate schedule who received a primary discount in the test period. Only one customer has dedicated service at 138 kV.

Rate Schedule	Bills with Primary Discounts
GS11	30
GS37	24
GS39	37
GS76	12
LGS13	309
LGS85	36
Total	448

b-e. The Company currently does not bill customers differently based on voltage and therefore does not have billing determinants or load research available as requested for the number of bills listed above or for any rate class other than the 138 rate proposed in this filing. The data request for the proposed 138 kV customer is currently presented in the Company class cost of service study and revenue proof.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 15.2

TEP's response to AECC Data Request 8.4 (a) was non-responsive. The question asked for the number of customers served at secondary, primary, and 138 kV voltage, based on adjusted test year billing determinants, for each of the six customer classes in TEP's class cost of service study. Instead, TEP provided the number of bills by rate schedule who received a primary discount in the test period. TEP provided no information regarding the service voltage of customers in the LPS (non-138 kV) class. Please provide the number of LPS (non-138 kV) customers served at secondary and primary voltage, based on adjusted test year billing determinants.

RESPONSE:

The Company believes the response provided to AECC Data Request 8.4 (a) was responsive. Only classes with customers large enough to utilize primary metering economically contain provisions allowing for a primary metering discount. The number of customers receiving that discount would represent the number of customers served with primary meters. Craig Jone's Direct Testimony indicated only one customer was served at the 138 kV level; therefore, all other customers were served at the secondary level. AECC is correct that the Company inadvertently left the LPS class off of the list. It was still being researched at the time the response was provided and was overlooked when the response went out.

For the 18 LPS customers during the test year, 9 customers were served at the primary level and 8 are served at the secondary level, with one additional customer being served at both the primary and secondary level.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC FIFTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 03, 2016

AECC 15.4

Follow up to TEP's response to AECC Data Request 8.5. Please confirm that only one LPS-TOU customer provides its own transformer in the test year.

RESPONSE:

Since the submission of the response to AECC 8.5 (which inadvertently omitted a statement stating the LPS class would require more time), the Company completed additional research for the LPS rate class and identified a total of 12 of the 18 LPS customers that own their transformers (one of the 18 is a non-TOU LPS customer being served with a customer owned transformer). Two of those 12 are being served by both customer owned transformers and Company-owned transformers. Including the 2 LPS-TOU customers that are being served by both Company and customer owned transformers, 8 of 18 LPS customers were served from Company owned transformers during the test year.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 16.3

Alternative Generation Service Experimental Rider.

a. How did TEP determine that 30 MW should be the appropriate maximum participation level if the program is adopted?

b. Please provide any analysis that TEP has performed in support of the Company's proposed management fee of $.0040/kWh.

c. In reaching the decision to purchase a 75% interest in the Gila River Power Plant Unit 3, did TEP consider the extent to which the amount of the Gila River capacity that was purchased could have been reduced by adoption of the Alternative Generation Service Experimental Rider or similar program? If yes, please provide copies of the analysis or studies. If not, please explain why TEP did not consider reducing the amount of capacity purchased by implementing the Alternative Generation Service Experimental Rider or similar program.

d. In reaching the decision to purchase a 49.5% interest in Springerville Unit 1, did TEP consider the extent to which the amount of the Springerville 1 capacity that was purchased could have been reduced by adoption of the Alternative Generation Service Experimental Rider or similar program? If yes, please provide copies of the analysis or studies. If not, please explain why TEP did not consider reducing the amount of capacity purchased by implementing the Alternative Generation Service Experimental Rider or similar program.

e. In reaching the decisions to add $103 million in investments in utility-scale solar generation since 2012, as reported on p. 26 in the direct testimony of David G. Hutchens, did TEP consider the extent to which the amount of the incremental solar capacity that was acquired could have been reduced by adoption of the Alternative Generation Service Experimental Rider or similar program? If yes, please provide copies of the analysis or studies. If not, please explain why TEP did not consider reducing the amount of capacity added by implementing the Alternative Generation Service Experimental Rider or similar program.

RESPONSE:

a. Based on the size of TEP's system and the risks associated with such an offering, as shown by APS's estimated loss of $16.8 million between November 2012 and May 2015 for their AG-1 program, the Company believed 30 MW is sufficient capacity to offer in a 4 year pilot.

b. TEP used the management fee for the APS AG-1 program as a starting point and made necessary adjustments. Because APS experienced net losses of approximately $16.8 million between November 2012 through May 2015 for their AG-1 program, TEP felt the management fee needed to be greater than APS's to help cover costs associated with the program.

c. No. As shown in the 2014 IRP, even with the planned acquisitions of both the 75% interest in Gila River Unit 3 and the 49.5% interest in Springerville Unit 1 as well as the build out of utility scale generation resources, TEP was still short 200 MW in peaking capacity in 2015 growing to a deficit of 570 MW in 2018 with the retirement of San Juan Unit 2. In future IRP planning cycles, the Company would factor in any approved Alternative

Generation Service Riders based on the firm capacity commitments within these approved tariff structures as part of its future resource plans.

d. See the response to AECC 16.3 c above.

e. See the response to AECC 16.3 c above.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC TWENTY FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
June 17, 2016

AECC 21.1

Mobile Home Park Electric Service – GS-11F.

a. Please define "new customers" as used in this rate schedule.

b. Please explain the rationale for not allowing new customers to take service under this rate schedule.

c. Assume that an existing master-metered mobile home park has been operating for ten years and takes service under the LGS-13 rate schedule. If this customer seeks to switch to the GS-11F rate schedule, would it be considered a "new customer" for purposes of the GS-11F rate schedule?

d. In determining the rate design and availability criteria for GS-11F, did TEP take into account the statutory requirement that master-metered mobile home parks must not charge their residents more than the utility's prevailing rates for basic single family residential service (Arizona Revised Statutes 33-1413.01)? If the answer is "yes", please provide any analysis that TEP conducted that took this statutory requirement into account when designing the GS-11F rate and determining its availability criteria. If the answer is "no" please explain why TEP did not take this statutory requirement into account.

e. In light of the statutory requirement that master-metered mobile home parks must not charge their residents more than the utility's prevailing rates for basic single family residential service, does TEP agree that it would be reasonable to offer a rate schedule designed specifically for customers subject to this statutory requirement? If yes, does TEP agree that it would be reasonable to remove the availability restriction on service to new customers? If TEP responds "no" to either of these questions, please explain the basis for TEP's disagreement.

RESPONSE:

a. The reference GS-11F has been replaced by the GS-M tariff. This tariff does not include a reference to "new customers". The tariff would not be made available to "new facilities". Any existing master metering facility would still be able to receive service under this tariff for their existing facilities.

b. Per the following AZ Administrative Code, R14-2-205, the Company wants to avoid master metered circumstances in the future.

R14-2-205. Master Metering

A. Mobile home parks -- new construction/expansion

1. A utility shall refuse service to all new construction or expansion of existing permanent residential mobile home parks unless the construction or expansion is individually metered by the utility. Line extensions and service connections to serve such expansion shall be governed by the line extension and service connection tariff of the appropriate utility.

2. Permanent residential mobile home parks for the purpose of this rule shall mean mobile home parks where, in the opinion of the utility, the average length of stay for an occupant is a minimum of six months.

3. For the purpose of this rule, expansion means the acquisition of additional real property for permanent residential spaces in excess of that existing at the effective date of this rule.

B. Residential apartment complexes, condominiums, and other multiunit residential buildings

1. Master metering shall not be allowed for new construction of apartment complexes and condominiums unless the building or buildings will be served by a centralized heating, ventilation or air conditioning system and the contractor can provide to the utility an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship.

c. Yes.

d. The master-metered mobile home park is the Company's customer since they are the entity the Company provides the bill to. The referenced statute is the responsibility of the master-metering customer, if they choose to bill the tenants of the mobile home park as sub-metered tenants. The amount billed to each tenant is the responsibility of the mobile home park, and, as such, must meet the requirements of the statute. The Company has no control over what the tenant receives as a bill; therefore, the referenced statute is not considered in the calculation of the rates charged to the non-residential customer. The rate being charged to the mobile home park is designed consistent with other non-residential customers of its size and service type.

e. The answer to the first question in this section is no. The Company does offer a residential rate to its customers. It is the mobile home park that chooses to sub-meter and must therefore abide by the statute. The restriction to "new facilities" is designed to be in compliance with the statute referenced in section b above.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWENTIETH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 19, 2016

STF 20.11

Cost of Service: Follow-up to UDR 1.085 - Average and Excess Demand ("AED") is defined using individual class NCP less average demand. On sheet AvgEx&4CP of 2015 TEP Schedule G – COSS Competitively Sensitive Confidential.xlsx row 21 shows the class 4 CP, row 25 shows the 4CP Allocator and row 23 shows the AED/4CP allocator. Rows 23 and 25 appear to be identical as confirmed on row 27.

a. Where are the class NCP used on this sheet?

b. Where are the class NCP used in the development of the AED&4CP allocator?

c. If there is an average demand component to AED then why is cell G23 equal to zero?

d. If there is an average component within AED then why does the Lighting class receive no allocation of fuel inventory on Schedules G-1 and G-2?

e. Please provide a calculation of the DPROD allocator using AED-NCP and the resulting Schedule G.

f. Please explain if the email dated October 13, 2015 provided in the UNSE case is still appropriate for the above situation.

RESPONSE:

a.-c. As explained in the referenced e-mail, the AED theory would typically use NCP to allocate excess and the Company used CP, therefore NCP is not shown in the tab AvgEx&4CP in the cost of service study. And as expressed in the e-mail, you are correct that if you use a peak to calculate excess demand and calculate the load factor on that peak the study produces the same outcome as the peak methodology.

d.-e Please see TEP's supplemental response to UDR 1.001 dated May 19, 2016.

f. For the most part, with the further changes incorporated in this response.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

REDACTED

Surrebuttal Testimony of Kevin C. Higgins

on behalf of

Freeport Minerals Corporation,

Arizonans for Electric Choice & Competition and

Noble Americas Energy Solutions LLC

EXHIBIT
AECC-10
ADMITTED

August 25, 2016

SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS

TABLE OF CONTENTS

SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who pre-filed direct revenue requirement testimony in this case on behalf of Freeport Minerals Corporation and Arizonans for Electric Choice and Competition ("AECC")[1] as well as direct cost of service/rate design testimony on behalf of AECC and Noble Americas Energy Solutions ("Noble Solutions")?

A. Yes, I am.

Q. What is the purpose of your Surrebuttal Testimony?

A. First, my Surrebuttal Testimony presents my recommendation in support of approval of the Settlement Agreement Regarding Revenue Requirement submitted by parties to the case and signed by AECC, Freeport Minerals Corporation, and Noble Solutions.

[1] Henceforth in this testimony, unless otherwise specified, Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

Second, in response to the issues raised by the Commission in a recent open meeting, as well as issues raised by parties to this case, I have prepared an alternative buy-through proposal for the Commission's consideration.

Third, my Surrebuttal Testimony presents my updated revenue allocation recommendations that are calibrated to the Settlement Agreement Regarding Revenue Requirement.

Fourth, my Surrebuttal Testimony responds to the Rebuttal Testimonies of Tucson Electric Power ("TEP") witnesses Craig A. Jones and Ramondo J. Robey on the topics of cost of service, rate design (including unbundled rates), the mobile home park rate schedule, the Lost Fixed Cost Recovery mechanism ("LFCR"), and the Purchased Power and Fuel Adjustment Clause ("PPFAC").

Fifth, my testimony responds to the recommendation of SWEEP witness Jeff Schlegel to recover $23 million of energy efficiency costs in base rates.

SUMMARY

Q. What are the primary conclusions and recommendations presented in your Surrebuttal Testimony?

A. I offer the following primary conclusions and recommendations:

(1) I recommend that the Commission approve the Settlement Agreement Regarding Revenue Requirement ("Partial Settlement Agreement") that has been submitted in this case.

(2) I am offering two buy-through options for the Commission's consideration. In my opinion, adoption of either program would be reasonable.

(a) The first buy-through option is described in my Direct Testimony. This option adopts some of the features of the buy-through program presented by TEP in its direct filing, but modifies other features to make the program open to a wider variety of customers, incorporating changes to program scale, eligibility, pricing, terms of return to standard generation service, and the mechanics of fixed generation cost recovery. A distinctive feature of this option is to absorb TEP's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers by applying the first $7.5 million of any revenue requirement reduction apportioned to the classes eligible for the buy-through program towards this purpose.

(b) The second buy-through option, described later in this testimony, is a five-year opt-out buy-through, similar to a program that has been implemented in the Portland General Electric ("PGE") service territory in Oregon. This proposal would require participating customers to pay a transition adjustment associated with their buy-through loads for a five-year transition period, after which the participating customers would continue to receive buy-through service with no further generation charge obligations to TEP, with the sole exception of unbundled fixed must-run generation charges. Under this program design, the burden of paying for fixed generation charges falls entirely on program participants, but in exchange, the participants are able to transition to 100% market pricing using the buy-through construct after five years.

(3) I recommend that the Commission adopt either of the rate spread proposals I present in Tables KCH-SR-1 or KCH-SR-2 in this Surrebuttal Testimony, depending on the Commission's determination regarding the buy-

through options I am proposing. My recommendations are more cost-based than either Staff or TEP, yet retain a significant residential subsidy, consistent with the principle of gradualism.

(4) The most reasonable basis for allocating costs in this case is the cost-of-service analysis I presented in my Direct Testimony, calibrated for the Partial Settlement Agreement. TEP's rebuttal cost-of-service study incorporates a number of the corrections I presented in my Direct Testimony, but TEP still improperly allocates distribution transformer costs to the LPS class and TEP still uses an incorrect measure of system load factor in its use of the Average and Excess Demand ("AED") method to allocate generation and transmission costs. TEP has also migrated, without explanation, to an AED method that uses non-coincident peak ("NCP") to allocate excess demand. However, this migration was unnecessary as TEP could have continued to use the 4CP AED method by incorporating a minor adjustment to ensure that excess demand for any class is not allowed to be less than zero.

(5) I recommend that TEP's rebuttal proposal to increase the basic service charge to $10,000 per month for LPS-TOU and $15,000 per month for High Voltage (138kV) be rejected, as the proposal is based on an erroneous foundation. Instead, I recommend that TEP's direct proposal to set the basic service charge at $2,000 per month for LPS-TOU and $3,000 per month for High Voltage be approved. I also recommend that TEP be ordered to correct the depiction of classified and functionalized unit costs in its class cost-of-service study in its next rate case in order to establish an accurate basis for rate design.

(6) I recommend that the Commission adopt the unbundled rates for the LGS, LPS, and High Voltage rate schedules presented in Exhibit KCH-SR-1. These rates were developed using my recommended rate spread in table KCH-SR-2, which comports to the Partial Settlement Agreement revenue requirement. If the Commission approves a rate spread that differs from my recommendation in Table KCH-SR-2, I recommend that the unbundled rates be calibrated from the rates I present in Exhibit KCH-SR-1, scaled to achieve the approved class revenue target.

(7) Currently, there are a handful of master-metered mobile home parks that are on the LGS rate schedule – a rate schedule with a significant demand charge and a 75% demand ratchet. This rate schedule is ill-suited for these customers because they are statutorily required to charge their residents TEP's residential rate – and the LGS rate design is a poor fit for customers with a residential load profile. These customers should be permitted to migrate to the Mobile Home Park rate schedule.

(8) TEP's proposal to cut off frozen Senior Lifeline and Medical Lifeline discounts to residents of master-metered mobile home parks should be rejected.

(9) TEP's proposed changes to the LFCR mechanism should be rejected. I also recommend that LGS customers be exempted from this charge going forward.

(10) The current PPFAC is structured to flow-through 100% of all deviations in fuel and purchased power costs to customers. This type of 100% cost pass-through seriously reduces a utility's incentive to manage its fuel and purchased power costs as well as it would manage them if it remained exposed to

the energy cost risk. In my opinion, a risk-sharing mechanism is essential to keep customer and Company interests aligned. Consequently, I recommend adoption of a 70/30 risk-sharing mechanism in the PPFAC.

(11) The PPFAC Plan of Administration was changed in the last general rate case to shift the profits realized from new long-term contracts to the benefit of TEP shareholders instead of customers. This change should be reversed going forward. Instead, all revenues from wholesale sales, irrespective of term, should be credited against fuel and purchased power costs and included in the PPFAC, unless such sales are allocated a share of system costs.

(12) The proposal by SWEEP witness Jeff Schlegel to include $23 million of energy efficiency program costs in base rates should not be adopted. The shifting of costs from the DSM Surcharge into base rates would result in a loss of transparency regarding the cost of the Company's energy efficiency programs. This information should not be hidden from customers.

SETTLEMENT AGREEMENT REGARDING REVENUE REQUIREMENT

Q. Did you prepare Direct Testimony on the subject of revenue requirement in this proceeding?

A. Yes, I did. In my Direct Testimony on the subject of revenue requirement, I recommended that TEP's revenue requirement be reduced by $48.6 million relative to TEP's direct case.

Q. Are you familiar with the Settlement Agreement Regarding Revenue Requirement ("Partial Settlement Agreement") that has been filed in this proceeding?

A. Yes, I am. I participated in the negotiations that resulted in the Partial Settlement Agreement. AECC, Freeport Minerals Corporation, and Noble Solutions are among the signatories to the agreement.

Q. Do you recommend Commission approval of the Partial Settlement Agreement?

A. Yes, I do. The Partial Settlement Agreement reduces TEP's non-fuel revenue requirement increase by $28 million relative to the Company's direct case and reduces the base cost of fuel by another $14.8 million, for a total reduction relative to TEP's direct case of $42.8 million. The Partial Settlement Agreement adopts a number of the recommended revenue requirement adjustments proposed by AECC, Staff, RUCO, and the Sierra Club. I believe the Partial Settlement Agreement represents a fair compromise on a specific set of issues and that approval of the agreement is in the public interest. However, as noted in Section 6.3 of the agreement, there are many important issues in this case that the Partial Settlement Agreement does not propose to resolve, including rate spread (i.e., class revenue allocation), approval of a buy-through tariff, design of the Purchased Power and Fuel Adjustment Charge ("PPFAC"), the Lost Fixed Cost Recovery ("LFCR") mechanism, cost allocation, and rate design. I will address each of these topics in my Surrebuttal Testimony.

BUY-THROUGH TARIFF

Q. In your Direct Testimony you supported adoption of a buy-through program and recommended a number of changes to the straw proposal that TEP

presented in its direct filing. Do you still advocate for adoption of the buy-through proposal presented in your Direct Testimony?

A. Yes, I do. While I believe it would be preferable to allow Arizona customers full access to the electric power marketplace to take advantage of the benefits of competition as intended by the Arizona Legislature, a buy-through program represents a compromise that provides customers the opportunity to engage in market transactions and potentially reduce their energy costs, consistent with state policy, but without implementing full direct access service. A successful buy-through program will enhance the economic development climate of the TEP service territory and of the state generally.

The buy-through program as recommended in my Direct Testimony adopts some of the features of the buy-through program presented by TEP, but modifies other features to make the program open to a wider variety of customers. My proposal incorporates changes to program scale, eligibility, pricing, terms of return to standard generation service, and the mechanics of fixed generation cost recovery. It also clarifies the program term.

A distinctive feature of the proposal in my Direct Testimony is to absorb TEP's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers by applying the first $7,550,207 of any revenue requirement reduction apportioned to the classes eligible for the buy-through program towards this purpose. As I discuss later in this Surrebuttal Testimony, I have reduced this amount to $7,470,705 to correspond to the Partial Settlement Agreement revenue requirement. Consistent with my proposal, both TEP and the customer classes not eligible to participate in the buy-through program would be held harmless from adoption of the buy-through provision. I continue to believe this is a reasonable approach to *initiating* a buy-through program. Over time, as TEP is able to account for the role of buy-through load in reducing the Company's need for generation resources in its integrated resource planning process, and if the program were to remain in place for an extended period, the basis for ascribing any loss of fixed generation revenues to buy-through customers would diminish and eventually disappear.

Q. Are you aware of the Commission's deliberations on the buy-through program that you proposed on behalf of AECC and Noble Solutions in the UNS Electric general rate case?

A. Yes, I am. I have reviewed the webcast of the Commission's discussion of this issue in its Open Meeting of August 10, 2016.

Q. Do you have any additional recommendations in this proceeding in response to the issues raised in the Commission open meeting?

A. Yes. In response to the issues raised and comments made in the Commission Open Meeting I have prepared an alternative buy-through proposal for the Commission's consideration. While I believe the buy-through proposal detailed in my Direct Testimony is reasonable, I also believe the alternative proposal, which I characterize as a "five-year opt-out buy-through" also is a reasonable alternative, and would be a valuable means to enhance the economic development of the State if adopted.

Q. Please describe your alternative buy-through proposal and why you characterize it as a five-year opt-out buy-through.

A. My alternative buy-through proposal would require participating customers to pay a transition adjustment associated with their buy-through loads for a five-year transition period, after which the participating customers would continue to receive buy-through service with no further generation charge obligations to TEP, with the sole exception of unbundled fixed must-run generation charges. Under this program design, the burden of paying for both market-based energy supply and fixed generation charges falls entirely on program participants, but in exchange, the participants are able to transition to 100% market pricing using the buy-through construct after five years. This would allow TEP to consider these load reductions in their long-term planning and allow remaining system load growth to help offset some perceived revenue losses raised by the Company. Critically, this program would not be a limited-term pilot, but would necessarily be a permanent program; otherwise it would be pointless for customers to pay the five-year transition charges and bear the risks associated with market pricing.

The main drawback to this program design is that there may be few, if any, power cost savings to the participating customer for the five-year transition period. This could discourage participation and would not provide the near-term rate relief that business customers in TEP's high-priced service territory may need. But on the other hand, (i) it would allow customers that are seeking a long-term migration to market pricing to reach that objective and (ii) could provide significant savings to Arizona job providers over the long run. This alternative program also addresses concerns that have been raised by opponents of my first proposal regarding the funding of fixed generation costs by placing the responsibility for these costs entirely on the participants – even though the participants would *not* be using TEP's generation assets for their power supply, but instead acquiring it in the market.

Q. Are you familiar with any similar five-year opt-out programs?

A. Yes. Portland General Electric ("PGE") in Oregon has a five-year opt-out program that uses this basic construct. One difference is that the PGE program is not a buy-through program, but provides direct access. However, the same basic parameters can be applied to a buy-through program.

The PGE five-year opt-out program has been in place since 2003. It is available to customers with demands of 200 kW that can aggregate up to at least 1 MWa.[2] It is limited to a total participation cap of 300 MWa, but is not fully subscribed at this time. Participating customers are subject to a transition charge that requires the participant to pay the difference between the cost-of-service generation rate and the market price of power, where the market price of power is projected for five years and shaped to reflect class seasonal and on-peak loads and is adjusted (upward) for wheeling costs and line losses. The upshot is that the opt-out customer continues to pay for PGE's fixed generation costs throughout the five-year transition period as well as the difference between the cost-of-service energy rate and the (adjusted) market price of power. The latter could be a credit if the market price is greater than the cost-of-service energy rate.

Customers can elect to participate annually during a 30-day shopping window. The reason for the shopping window is to allow market prices to be "locked down" for purposes of the transition charge calculation.

[2] Note: 1 MWa corresponds to 1 average MW.

PGE's five-year opt-out customers continue to pay for unbundled distribution service, as applicable.

Q. Why is the recovery of fixed generation charges limited to a five-year period?

A. The opt-out program is intended to be a permanent, or long-term, exit from cost-of-service rates. By joining the program, the customer is giving the utility notice that it need no longer to plan to provide generation service to this customer. A five-year transition period gives the utility time to adjust its resource planning to take account of the departed load.

Q. Can PGE opt-out customers ever return to cost-of-service rates?

A. Yes, but only after providing three-years' advance notice.

Q. What is your specific proposal for a five-year buy-through opt-out program for TEP?

A. My proposed five-year opt-out program has the following features:

- The program would be open to any customer with an aggregated load of 1,000 kWa or greater using facilities that have a maximum billing demand of at least 200 kW over the 12 month period prior to enrollment.
- Initially, program participation would be capped at 150 MWa, which is comparable to the cap for the PGE program, given the relative size of the two utilities.[3] Over time, in conjunction with the Integrated Resource Planning process, the cap would be increased to match projected load growth and/or to offset the acquisition of new generation resources.
- Participating customers would not pay for TEP's unbundled generation charges (inclusive of fixed generation charges, base power supply charges,

[3] PGE's load for larger non-residential customers is approximately twice the size of TEP's.

the PPFAC,[4] the Environmental Compliance Adjustor, and the Renewable Energy Standard and Tariff ["REST"] Surcharge)[5] but would be required to pay a transition charge for five years. The transition charge would be published prior to a 30-day enrollment period each year. For any vintage enrollment period (e.g., 2017 -2021) the transition charge would be locked in at the outset and would apply for the duration of the transition period. At the conclusion of the transition period, participating customers would have no further transition charge obligation to TEP.

- The transition charge would require the participant to pay the difference between the cost of service unbundled generation charges (inclusive of base power supply charges, but exclusive of riders) and the market price of power, where the market price of power and base power supply charges are projected for five years and shaped to reflect class seasonal and on-peak loads and is adjusted (upward) for wheeling costs and line losses. For the purpose of this calculation, the fixed generation charge would be based on the unbundled generation rates in effect at the time of enrollment.
- Participating customers would continue to pay TEP's unbundled distribution and transmission charges, both throughout the transition period and after the transition period is concluded.
- Participating customers located within a TEP-transmission-constrained area would also continue to pay TEP's unbundled fixed must-run

[4] A one-year payment of the PPFAC true-up component would be appropriate.
[5] Exemption from the REST surcharge would be appropriate because buy-through customers would not receive the benefit of the generation procured from this surcharge.

generation costs, both throughout the transition period and after the transition period is concluded. At the same time, the buy-through customers paying this charge will be entitled to service from TEP's must-run facilities at cost-based energy rates during periods of transmission congestion.

- Opt-out customers could only return to cost-based rates with three-years' advance notice.
- Imbalance charges would apply when scheduled power deliveries do not match actual loads.

Q. **In the buy-through proposal that you described in your direct testimony you included provisions for a 15% generation reserve charge and a management fee of $0.002 per kWh. Are you including either of those charges in your alternative five-year opt-out proposal?**

A. Not in the same manner as I proposed for the buy-through program described in my Direct Testimony. During the five-year transition period for the opt-out proposal participating customers will be paying for 100% of TEP's fixed generation charges, even though the participants would be acquiring their generation product from another source. This large expense more than compensates the Company for generation reserves and management fees that otherwise would be appropriate for a program without transition charges. At the conclusion of the transition period, the reserve generation charge would be unnecessary if the participant purchases firm power, although an imbalance charge would be appropriate, as I discussed above. At the end of the transition period, a small management fee of $0.002/kWh would be appropriate to compensate TEP for providing the buy-through service.

Q. **Does your proposal for assessment of a transition charge on five-year opt-out customers constitute an acknowledgement that TEP is entitled to stranded cost recovery from shopping customers?**

A. No, not at all. In Docket No. E-01933A-98-0471, et al., TEP was awarded stranded cost recovery over an approximately nine-year period associated with the implementation of direct access service for all customers. Accordingly, TEP's stranded cost recovery was fully completed by December 31, 2008. My proposal for a five-year transition charge is intended to forge a middle ground that would allow a long-term buy-through program to move forward, while allowing TEP to fully recover its revenue requirement in this proceeding without affecting any non-participating customers. This compromise proposal is not intended to concede any argument with respect to the termination of TEP's stranded cost recovery pursuant to the Commission's order approving the amended settlement agreement in Docket No. E-01933A-98-0471.

Q. **Please summarize your recommendations concerning the approval of a buy-through program for TEP.**

A. I am offering two buy-through options for the Commission's consideration. In my opinion, adoption of either program would be reasonable.

The first option is described in my Direct Testimony. This option adopts some of the features of the buy-through program presented by TEP, but modifies other features to make the program open to a wider variety of customers, incorporating changes to program scale, eligibility, pricing, terms of return to standard generation service, and the mechanics of fixed generation cost recovery. A distinctive feature of this option is to absorb TEP's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers by applying the first $7.5 million of any revenue requirement reduction apportioned to the classes eligible for the buy-through program towards this purpose. Consistent with my proposal, both TEP and the customer classes not eligible to participate in the buy-through program would be held harmless from adoption of the buy-through provision.

The second option as described in this Surrebuttal Testimony is a five-year opt-out buy-through, similar to a program that has been implemented in the PGE service territory in Oregon. This proposal would require participating customers to pay a transition adjustment associated with their buy-through loads for a five-year transition period, after which the participating customers would continue to receive buy-through service with no further generation charge obligations to TEP, with the sole exception of unbundled fixed must-run generation charges. Under this program design, the burden of paying for fixed generation charges falls entirely on program participants, but in exchange, the participants are able to transition to 100% market pricing using the buy-through construct after five years. This alternative program addresses concerns that have been raised by opponents of my first proposal regarding the funding of fixed generation costs by placing the responsibility for these costs entirely on the participants – even though the participants would *not* be using TEP's generation assets for their power supply, but acquiring it in the market. It also addresses any concerns regarding the ability of utilities to plan for a customer's departure. In addition, it is intended to be responsive to Commission requests during the August 9-11, 2016 Open Meeting for additional competitive generation service programs they might consider.

REVENUE ALLOCATION

Q. Have you updated your recommended revenue allocation to reflect the revenue requirement recommended in the Partial Settlement Agreement?

A. Yes, I have. My recommended revenue allocations are presented in Table KCH-SR-1 and KCH-SR-2, below. Table KCH-SR-1 presents my recommended rate spread in combination with my initial buy-through proposal, i.e., it includes an allocation of $7.5 million to fund the buy-through program. Table KCH-SR-2 presents my recommended rate spread in combination with my alternative buy-through proposal, i.e., there is no special allocation in the revenue allocation to fund the buy-through program because it would be funded from program participants. This rate spread would also apply if no buy-through program is adopted.

Table KCH-SR-1

AECC / Noble Solutions Recommended Rate Spread
at Settlement Revenue Requirement
and Initial Buy-Through Option

Customer Class	Current Adjusted Test Year Sales Revenue	AECC/Noble Solutions Proposed Sales Revenue	AECC/Noble Solutions Proposed $ Change	AECC/Noble Solutions Proposed % Change
(a)	(b)	(c)	(d)	(e)
Residential	402,568,874	475,866,481	73,297,608	18.2%
General Service	221,889,211	238,229,710	16,340,499	7.4%
Large General Service	144,368,117	139,727,495	(4,640,621)	-3.2%
Total LPS (TOU & 138kV)	121,981,574	119,419,658	(2,561,915)	-2.1%
Large Power Service	[redacted]			
High Voltage 138kV				
Lighting	4,638,212	5,713,602	1,075,390	23.2%
Sub-Total	895,445,987	978,956,947	83,510,960	9.3%
Experimental Rider-14 Reserve		(7,470,705)	(7,470,705)	
Total	895,445,987	971,486,241	76,040,254	8.5%

Table KCH-SR-2

AECC / Noble Solutions Recommended Rate Spread
at Settlement Revenue Requirement
and Alternative Buy-Through Option

Customer Class	Current Adjusted Test Year Sales Revenue	AECC/Noble Solutions Proposed Sales Revenue	AECC/Noble Solutions Proposed $ Change	AECC/Noble Solutions Proposed % Change
(a)	(b)	(c)	(d)	(e)
Residential	402,568,874	475,866,481	73,297,608	18.2%
General Service	221,889,211	238,229,710	16,340,499	7.4%
Large General Service	144,368,117	135,391,010	(8,977,107)	-6.2%
Total LPS (TOU & 138kV)	121,981,574	116,285,438	(5,696,135)	-4.7%
Large Power Service	[redacted]			
High Voltage 138kV				
Lighting	4,638,212	5,713,602	1,075,390	23.2%
Total	895,445,987	971,486,241	76,040,254	8.5%

Q. Are your recommended revenue allocations consistent with the parameters you proposed in your Direct Testimony?

A. Yes. I am recommending that the revenue requirements for both the LPS and High-Voltage rate schedules be set at cost using my adjusted cost-of-service analysis (as described in my Direct Testimony) calibrated for the revenue requirement presented in the Partial Settlement Agreement and the updated class load data included in TEP's rebuttal filing. I also recommend reducing the GS and LGS revenue allocation such that the rates for each class are no more than 12.5% above cost of service (at TEP's initial overall revenue requirement), also calibrated for the revenue requirement presented in the Partial Settlement Agreement. The sum of these net adjustments is offset by a corresponding adjustment in the revenue allocation to the Residential class, which would also move this class closer to its cost of service, although a considerable subsidy would still remain in residential rates.

Q. Please explain the overall rate increase of $76 million in your tables.

A. My recommended rate spreads tie directly to the $81.5 million non-fuel rate increase in the Partial Settlement Agreement, but I show the net increase from today's rates, including today's fuel costs. Thus, my rate spreads reflect the net reduction in fuel costs from today's rates. The net increase from today's rates, including fuel, in the Partial Settlement Agreement amounts to $76 million.

Q. Please explain the genesis of the current adjusted sales revenue in your tables.

A. As I explained in my Direct Testimony, TEP is proposing to create a new Medium General Service ("MGS") rate schedule and a new High Voltage rate schedule, as well as requiring certain customers to migrate between existing classes. Accordingly, I have adjusted current revenues in the tables above to reflect TEP's proposed composition of each class. I also include *current fuel revenues* (at the current PPFAC rate of $0.001501/kWh) in present revenues, rather than *proposed* fuel revenues as TEP presents in its Schedule H-1. Finally, my present sales revenues reflect the pro forma load changes that TEP has incorporated into its case. I believe these adjustments make the rate impacts presented in my tables more meaningful than they would be if these adjustments had not been made.

Q. How do your recommended rate spreads compare with those recommended by TEP and Staff?

A. At this juncture in the case, the rate spreads presented by TEP, Staff, and AECC/Noble Solutions each correspond to different revenue requirements.[6] Consequently, they are not directly comparable in this Surrebuttal Testimony. However, some inferences can be drawn. For example, TEP's rebuttal rate spread, which I have presented below in Table KCH-SR-3, shifts relatively greater revenue responsibility to non-residential classes than the Company's rate spread presented in its direct case. In my opinion, this represents a step in the *wrong* direction relative to cost-of-service.

[6] TEP's most recent rate spread is its rebuttal rate spread. The most recent Staff rate spread available for my review at the time of this filing is for Staff's direct case. And my recommended rate spread in this filing is for the Partial Settlement Agreement revenue requirement.

Table KCH-SR-3

TEP Rebuttal Rate Spread
Current Sales Adjusted for Rate Migration, Net Load Reduction, and Current Fuel Costs

Customer Class	Current Adjusted Test Year Sales Revenue[1]	TEP Proposed Sales Revenue[2]	TEP Proposed $ Change	TEP Proposed % Change
(a)	(b)	(c)	(d)	(e)
Residential	402,568,874	462,043,268	59,474,394	14.8%
General Service	221,889,211	251,565,091	29,675,880	13.4%
Large General Service	144,368,117	149,542,269	5,174,153	3.6%
Total LPS (TOU & 138kV)	121,981,574	126,074,875	4,093,302	3.4%
Large Power Service	[redacted]	[redacted]	[redacted]	[redacted]
High Voltage 138kV	[redacted]	[redacted]	[redacted]	[redacted]
Lighting	4,638,212	5,991,010	1,352,798	29.2%
Total	895,445,987	995,216,513	99,770,526	11.1%

Data Sources:
1. AECC/Noble Solutions Adjusted Present Revenue workpaper.
2. TEP Witness Craig Jones Rebuttal Testimony, Exhibit CAJ-R-3, Sch. H-2-2, & Rebuttal CCOS Model (Competitively Sensitive Confidential).

Q. The heading for Table KCH-SR-3 indicates that current sales are adjusted for rate migration, net load reduction, and current fuel costs. What does that mean?

A. As I explained above, TEP is proposing to create a new Medium General Service rate schedule and a new High Voltage rate schedule, as well as requiring certain customers to migrate between existing classes. However, in presenting its class revenue changes, TEP does not update current revenues to reflect the new composition of the classes. That is, in TEP's Schedule H-1, for example, the *proposed* revenues reflect the *new* class composition, while the *current* revenues reflect the *old* (current) class composition, which makes the *change* in revenues presented in Schedule H-1 almost meaningless for several classes.

In order to avoid this pitfall I have adjusted current revenues in Table KCH-SR-3 to reflect TEP's proposed composition of each class. Also, consistent with the preceding tables, I include *current* fuel revenues (at the current PPFAC rate of $0.001501/kWh) in present revenues, rather than *proposed* fuel revenues as TEP does. Finally, my present sales revenues reflect the pro forma load reduction that TEP has incorporated into its rebuttal case.

Q. What are your observations regarding Staff's proposed revenue allocation?

Staff's recommended rate spread from the Direct Testimony of Howard Solganick is reproduced in Tables KCH-SR-4 and KCH-SR-5 below. As an initial matter, I note that I have reproduced Mr. Solganick's recommendations without any adjustments to current revenues (or "test year" revenues) to reflect TEP's proposed rate migrations. I have done so to reflect what I believe are Mr. Solganick's intentions. However, because Mr. Solganick apparently has not adjusted current revenues to reflect load migration (except for the new 138 kV rate schedule), I believe that the class revenue requirements that Mr. Solganick is recommending would <u>not</u> result in the rate impacts on customers that are presented in his exhibits. In other words, as is the case with TEP's Schedule H-1, the current revenues (or test year revenues) in Mr. Solganick's exhibits appear to be prior to load migration. If his proposed revenues are *after* load migration, then they will not produce the rate impacts on customers that are indicated in his Exhibit HS-4.

Overall, while Staff makes some attempt to move in the direction of cost causation, Staff's proposed revenue allocation nevertheless contains larger residential subsidies than either my recommendation or TEP's.

Table KCH-SR-4
Staff Recommended Rate Spread, Direct Case – Margins

Customer Class	Staff Test Year Margin Revenue[1]	Staff Proposed Margin Revenue[1]	Staff Proposed Margin $ Change[1]	Staff Proposed Margin % Change[1]
(a)	(b)	(c)	(d)	(e)
Residential	275,887,975	318,962,556	43,074,581	15.6%
General Service	184,448,887	186,914,392	2,465,505	1.3%
Large General Service	68,460,569	69,640,122	1,179,553	1.7%
Total LPS (TOU & 138kV)	73,302,768	74,606,369	1,303,601	1.8%
Large Power Service	[redacted]			
High Voltage 138kV				
Lighting	3,298,783	4,675,543	1,376,760	41.7%
Total	605,398,982	654,798,982	49,400,000	8.2%

1. Data Source: Staff Witness Howard Solganick Direct Testimony, Exhibit HS-4 & HS-4 workpaper (Confidential).

Table KCH-SR-5
Staff Recommended Rate Spread, Direct Case – Total Revenues

Customer Class	Staff Test Year Sales Revenue[1]	Staff Proposed Sales Revenue[1]	Staff Proposed $ Change[1]	Staff Proposed % Change[1]
(a)	(b)	(c)	(d)	(e)
Residential	411,612,761	447,641,027	36,028,266	8.8%
General Service	263,144,831	251,625,319	(11,519,512)	-4.4%
Large General Service	111,478,013	120,383,208	8,905,195	8.0%
Total LPS (TOU & 138kV)	136,146,844	133,043,366	(3,103,478)	-2.3%
Large Power Service	[redacted]			
High Voltage 138kV				
Lighting	4,757,818	6,031,752	1,273,934	26.8%
Total	927,140,266	958,724,672	31,584,406	3.4%

1. Data Source: Staff Witness Howard Solganick Direct Testimony, Exhibit HS-4 & HS-4 workpaper (Confidential).

Q. Please summarize your recommendations concerning rate spread.

A. I recommend that the Commission adopt either of the rate spreads I am recommending in Tables KCH-SR-1 or KCH-SR-2, depending on the Commission's determination regarding the buy-through options I am proposing.

My recommendations are more cost-based than either Staff or TEP, yet retain a significant residential subsidy, consistent with the principles of gradualism.

<u>**COST OF SERVICE**</u>

Q. Your Direct Testimony supported TEP's overall selection of cost allocation method for generation and transmission but also included several recommended changes and corrections to TEP's study. How has TEP responded to your recommendations in its rebuttal filing?

A. In his Rebuttal Testimony, TEP witness Craig A. Jones responds to my critique by stating that the Company made two corrections to items I identified in the discovery process. Specifically, (i) TEP corrected its initial oversight in which the Company initially failed to allocate any Meters or Services costs to the Large General Service ("LGS") class. In addition, TEP (ii) corrected its initial error in which the Company allocated customer-related distribution costs based on NCP demand rather than number of customers.

Further, TEP corrected the error in its direct filing in which the Company did not allocate any portion of Other Operating Revenues to the proposed High Voltage (138 kV) class.

In addition, TEP accepted my correction to the allocation of Administrative & General ("A&G") expenses, which the Company had apparently inadvertently allocated entirely on the number of customers. This correction benefits Residential and Lighting customers, who were negatively impacted by TEP's initial allocation of these costs.

Q. Does TEP accept any of your other recommended changes to its cost-of-service calculation?

A. Apparently not. Mr. Jones indicates that TEP does not agree with all of my recommendations pertaining to the cost-of-service study, but he provides no discussion or rebuttal on any of the cost-of-service items with which he disagrees.

Q. Please restate the cost-of-service issues that remain at issue between you and the Company.

A. There are three cost-of-service issues remaining between TEP and my recommendations.

First, as I explained in my Direct Testimony, despite specifying in its tariff that Large Power Service – Time of Use ("LPS-TOU") customers are to provide their own transformers and are subject to primary service and metering, TEP allocates line transformer costs to the LPS class.[7] This treatment constitutes an improper cost allocation. In rebuttal, TEP offers no substantive response to my argument. TEP's position on this issue is unjustified and should be rejected.

Second, in my Direct Testimony I recommended a specific change to TEP's calculation of load factor as used in the 4CP AED method. Specifically, TEP uses an incorrect measure of system load factor for determining the proportion of plant cost that is allocated on the basis of average demand (or energy). Rather than using the retail system peak demand in the denominator of the load factor calculation, TEP averages the retail peak demands of the four coincident peak months. In my view, this approach does not accurately measure system load factor for the test year, and overstates the annual load factor above its

[7] *See* Direct Testimony of Kevin C. Higgins, Cost of Service/Rate Design, pp. 18-20.

true value. By doing so, TEP unreasonably shifts cost responsibility to higher load factor classes. Instead, system load factor should be measured by reference to TEP's highest peak demand for that year. This treatment is consistent with the method for measuring system load factor presented in the discussion of the AED method in the NARUC Manual. In addition to being conceptually correct from the standpoint of cost allocation, measuring load factor with respect to the highest peak demand is consistent with the approach TEP uses in assessing its load and resource balance as documented in the Company's integrated resource plan.[8]

Q. Does TEP respond to your criticism on this point?

A. No. TEP provides no discussion or justification for its use of an "average" load factor. TEP's rebuttal cost-of-service model simply continues to the same incorrect measure of load factor as TEP uses in its direct cost-of-service model.

Q. What is the third remaining item of disagreement regarding cost-of-service?

A. In TEP's rebuttal cost-of-service model, the Company has apparently switched – without discussion – from the 4CP AED method – to an AED approach that measures excess demand using 4 non-coincident demands ("NCP") rather than 4 coincident demands ("4CP"). This switch is unnecessary. The 4CP AED method is used in Colorado and Texas and is reasonable method for a utility with a pronounced summer peak such as TEP.[9] As I pointed out in my Direct Testimony, the 4CP AED approach simply requires a minor adjustment to account for classes, such as Lighting, that have little or no load during the system peak.[10]

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[8] See TEP 2014 IRP, pp. 28-29.
[9] In my Direct Testimony I stated that the 4CP AED variant was used by APS and UNS Electric. This is incorrect. These utilities use NCP rather than 4CP to measure excess demand.
[10] *See* Direct Testimony of Kevin C. Higgins, Cost of Service/Rate Design, p. 14.

The adjustment that should be made is to include a constraint that ensures that excess demand for any class is not allowed to be less than zero.

If this minor adjustment is made then there is no need to switch from the 4CP AED to an AED approach that uses NCP to allocate excess demand. Further, TEP's switch is further complicated by its unconventional use of <u>four</u> NCPs in its rebuttal model. I am not aware of any other utility that uses <u>four NCPs</u> to allocate excess demand.

Q. Please summarize your position concerning class cost-of-service.

A. The most reasonable basis for allocating costs in this case is the cost-of-service analysis I presented in my Direct Testimony, calibrated for the Partial Settlement Agreement revenue requirement and the updated class load data included in TEP's rebuttal filing. TEP's rebuttal cost-of-service study incorporates a number of the corrections I presented in my Direct Testimony, but TEP still improperly allocates distribution transformer costs to the LPS class and TEP still uses an incorrect measure of system load factor in its use of the AED method to allocate generation and transmission costs. TEP has also migrated, without explanation, to an AED method that uses NCP to allocate excess demand. However, this migration was unnecessary as TEP could have continued to use the 4CP AED method by incorporating a minor adjustment to ensure that excess demand for any class is not allowed to be less than zero.

RATE DESIGN: LPS-TOU AND HIGH VOLTAGE (138KV) BASIC SERVICE CHARGES

Q. What has Mr. Jones proposed in his Rebuttal Testimony regarding the LPS-TOU and High Voltage basic service charges?

A. The current LLP-90 customer charge is $2,000 per month, and TEP's direct rate design proposal maintained the basic service charge for LPS-TOU at $2,000 per month, while proposing a basic service charge for the High Voltage kV tariff of $3,000 per month. However, Mr. Jones's Rebuttal Testimony proposes to increase the basic service charge to $10,000 per month for LPS-TOU and to $15,000 per month for High Voltage, while reducing the demand charges.[11]

Q. Why has Mr. Jones proposed to increase the LPS-TOU and High Voltage basic service charges?

A. The Direct Testimony of Staff witness Howard Solganick prompted TEP to explain the difference between the LPS customer costs reported in the cost-of-service study and TEP's proposed basic service charge. According to Mr. Jones, the cost-of-service study indicates that the LPS basic service charge could be as high as $17,500 per month,[12] so TEP is proposing substantial movement toward that number.

Q. Do you agree with the depiction of customer-related costs in TEP's cost of service study?

[11] Rebuttal Testimony of Craig A. Jones, p. 19.
[12] TEP's Rebuttal cost-of-service study indicates that LPS customer-related costs are over [redacted] per customer, per month.

A. No. As I addressed in my Direct Testimony,[13] the depiction of the components that make up each class's allocated costs by classification and function is distorted in TEP's class cost-of-service study, as summarized on Schedule G-6-1. The customer-related components presented on Schedule G-6-1 for the LPS and High Voltage classes are inflated, and are inconsistent with the composition of allocated costs on Schedules G-3 and G-4 for these classes. This error occurs as the cost allocation results from Schedules G-3 and G-4 are translated onto the class-specific functional cost tabs, which are the basis for the unit costs on Schedule G-6-1. The erroneous depiction of customer-related costs occurs for cost items classified as both customer and demand-related, e.g., certain distribution costs, Intangible Plant costs, General Plant costs, and A&G expenses.

For example, the error can be appreciated by comparing the Distribution O&M expenses allocated to the LPS class on Schedule G-4 with the depiction of Distribution O&M expenses on the "LPS byFunction" worksheet of TEP's rebuttal cost- of-service model. On Schedule G-4, the LPS class is allocated [redacted] of distribution O&M expense, [redacted], or 95%, of which is demand-related and [redacted], or 5%, of which is customer related. This reflects the fact that the LPS class is responsible for a larger share of demand-related costs than customer-related costs, since it is a class comprised of a relatively small number of customers with relatively large loads.

However, on the "LPS byFunction" worksheet, this same [redacted] of distribution O&M expense is depicted as [redacted] (or 69%) demand-related and [redacted] (or 31%) customer-related. This error occurs because on the "LPS

[13] Direct Testimony of Kevin Higgins on Cost of Service/Rate Design, p. 6, lns. 10-12, and pp. 44-45.

byFunction" tab, allocated costs by FERC account are broken out into classified and functionalized portions based on the overall composition of each cost *for the system*, rather than the composition of each cost *for each class*. While the total allocated costs for each class are unaffected by this error, the depiction of costs by classification (demand or customer-related) and function is distorted for numerous FERC accounts. Specifically, the error occurs for FERC accounts that serve multiple functions (such as General Plant) and/or are comprised of both demand-related and customer-related costs (such as Distribution Plant FERC accounts 364, 365, 367, and 368).

These erroneous results are the basis for the unit costs on Schedule G-6-1, and are an improper foundation for rate design.

Q. What is your recommendation to the Commission regarding the LPS and High Voltage basic service charges?

A. I recommend that TEP's rebuttal proposal to increase the basic service charge to $10,000 per month for LPS-TOU and $15,000 per month for High Voltage be rejected, as the proposal is based on an erroneous foundation. Instead, I recommend that TEP's direct proposal to set the basic service charge at $2,000 per month for LPS-TOU and $3,000 per month for High Voltage be approved. I also recommend that TEP be ordered to correct the depiction of classified and functionalized unit costs in its class cost-of-service study in its next rate case in order to establish an accurate basis for rate design.

UNBUNDLED RATE DESIGN

Q. In your Direct Testimony you criticized TEP's unbundled rate design because it overstates distribution charges and understates generation charges. Has TEP responded to your criticism?

A. Yes. In his Rebuttal Testimony, Mr. Jones agrees that some additional cost could be moved to the generation component, but he does not agree that I have unbundled the costs appropriately. He goes on to add that "at the very least, the fixed must run cost and some of the other ancillary costs should remain in the Distribution component because they are needed to maintain stability of the system."[14] Mr. Jones indicates a willingness on the part of TEP to discuss this issue further, but he offers no specifics in his testimony.

Q. Do you have any response to Mr. Jones's comments?

A. Yes. Mr. Jones apparently misunderstands my treatment of fixed must-run costs and ancillary services. I did not include these items in the generation component, but leave them as standalone rate components. Further, I do not consider them to be bypassable for buy-through customers. Consequently, I do not see that there is any basis for disagreement between TEP and me on the basic treatment of fixed must-run costs and ancillary services.

Q. In your Direct Testimony you prepared unbundled rates for the LGS, LPS, and High Voltage rate schedules at your recommended rate spread and TEP's revenue requirement. Have you updated these rates to comport with the Partial Settlement Agreement revenue requirement?

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[14] Rebuttal Testimony of Craig A. Jones, pp. 51-52.

A. Yes. I have updated my recommended unbundled rates for the LGS, LPS, and High Voltage rate schedules using my recommended rate spread in table KCH-SR-2, which comports to the Partial Settlement Agreement revenue requirement. These rates are presented in Exhibit KCH-SR-1. In designing these rates, I used the same principles that I explained in my Direct Testimony, but calibrated to the new class revenue requirement.

Q. What is your recommended approach to designing unbundled rates if the Commission approves a rate spread that differs from your recommendation in Table KCH-SR-2?

A. In that case, I recommend that the unbundled rates be calibrated from the rates I present in Exhibit KCH-SR-1, scaled to achieve the approved class revenue target.

MOBILE HOME PARK RATE SCHEDULE

Q. In your Direct Testimony, you argued that tariff restrictions preventing existing mobile home parks from switching to the Mobile Home Park rate schedule are unjust and unreasonable and should be removed. How has TEP responded to your argument?

A. TEP opposes my recommendation. In support of the Company's position Mr. Jones cites to R14-2-205, which requires a utility to refuse service to all new construction or expansion of permanent mobile home parks unless the construction or expansion is individually metered.[15]

Q. Do you believe that R14-2-205 is applicable to your recommendation?

[15] Id., p. 52.

A. No. My proposal is directed to *existing* master-metered mobile home parks taking service under rate schedules other than the Mobile Home Park schedule. As I explained in my Direct Testimony, R14-2-205 already precludes new master metering in the future for mobile home parks *by requiring utilities to refuse service* to such new facilities. By the same token, if a master-metered mobile home park is already being served by TEP, it must be presumed to be an older facility that predates the prohibition on new master metering. If such a customer happens to be on the wrong rate schedule, no public interest is served in preventing this customer from switching to the Mobile Home Park rate schedule intended for such customers.

Q. Does Mr. Jones provide additional objections to your proposal?

A. Yes. In response to my argument that requiring service under alternate rate schedules such as LGS causes undue harm to master-metered mobile home parks, Mr. Jones responds that master-metered facilities that feel they are burdened by TEP's rate structure can allow TEP to individually meter their customers under standard residential rates.

Q. Why doesn't this approach solve the problem?

A. It would solve the problem if the process was as simple as Mr. Jones makes it seem. However, in reality TEP does not make things that simple. For TEP to take over metering responsibility for a mobile home park, the Company would also require upgrades to the existing mobile home park distribution infrastructure to meet TEP specifications at the owner's expense. I know from working with a client that was interested in having TEP take over its metering that this can be a cost-prohibitive option. Mr. Jones's rather cavalier suggestion is not a real solution to this problem.

Q. **Mr. Jones is also critical of your analysis that demonstrates the inappropriateness of having mobile home parks take service on the LGS rate schedule. Do you wish to respond?**

A. Yes. To illustrate the inaptness of the LGS rate schedule for a mobile home park operator, in my Direct Testimony I modeled the rate differential between the current LGS-13 and Residential rates using the typical load characteristics of a mobile home park on the Mobile Home Park rate schedule. This comparison is important because Arizona Revised Statute § 33-1413.01 requires that master-metered mobile home parks must not charge their residents more than the utility's prevailing rates for basic single family *residential* service. Because of this statute, it is important that there be a reasonable nexus between what TEP charges a master-metered mobile home park for power and what TEP charges a residential customer for power, because the mobile home park operator can only pass on the latter charges to its residents.

Mr. Jones criticizes my calculation because the monthly demand of the average-size mobile home park operator is less than the 200 kW minimum demand for the LGS rate schedule. Therefore, Mr. Jones argues, the LGS comparison I made was not reasonably representative for a customer that size. However, in defense of my calculation, I did not apply the minimum demand provision to it so as to not overstate the rate impact of that provision. Nevertheless, in response to this criticism, I have recalculated the rate impact of a customer with a mobile home park load profile but with a billing demand of 400 kW in the summer months and 200 kW in the non-summer months. The results of this calculation are shown in Exhibit KCH-SR-2. The exhibit shows that even at a 400 kW maximum demand, the current LGS-13 rate schedule is more expensive than current residential rates (15.25 cents per kWh versus 13.12 cents per kWh), reconfirming my point that it is unreasonable to prohibit existing mobile home parks from migrating to the Mobile Home Park rate schedule. Moreover, Mr. Jones's own Rebuttal Testimony demonstrates that the MGS rate schedule for a mobile home park is also more expensive than residential rates.[16]

Q. Does Mr. Jones offer any additional analysis on this point?

A. Yes. Mr. Jones states:

> The Company has identified 4 LGS-13 customers who are mobile home parks. These customers are not hurt as significantly as Mr. Higgins indicates. For the proposed rates, they pay an average of 13.97 cents per kWh, which is less than the proposed residential rate of 14.16 cents per kWh.[17]

Q. What is your response to this contention?

A. Interestingly, TEP offers this analysis after denying me access to this very information through discovery, claiming it would be too burdensome to provide.[18]

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[16] Id., pp. 53-54.
[17] Id., p. 54.
[18] To assist in the preparation of my Direct Testimony on this topic, AECC sent TEP the following discovery requests:

> **AECC 21.2 Mobile Home Park load.**
> a. What is TEP's best estimate of the number of mobile home parks in its service territory that are taking service under a rate schedule other than GS 11-F?
> b. What is TEP's best estimate of the annual billing demand and kWh sales of the mobile home parks in its service territory taking service under a rate schedule other than GS 11-F?

TEP replied as follows:

> The Company has not identified all mobile home parks in its service territory taking service under other than the GS-11F tariff. To identify and estimate this information would be overly burdensome therefore the Company objects to the request on that basis.

More significantly, Mr. Jones's analysis shows that under proposed rates – which are subject to change in this case – the average LGS rate in his group is very close to the residential rate. Further, I note that the *average* relationship between proposed LGS and residential rates for the group does not necessarily reflect the relationship for each member of the group. Individual mobile home parks on the LGS rate schedule should still be free to migrate to the Mobile Home Park rate.

Q. Are there other characteristics of the LGS rate schedule that make it inappropriate for mobile home parks that must charge residential rates to their residents?

A. Yes. The LGS rate schedule is subject to a 75% demand ratchet. This means that a mobile home park's demand charges in the non-summer months cannot fall below 75% of its summer demand charges, when residential air conditioning load is at its maximum. While this rate design provision may be appropriate for a true commercial or industrial customer, it is extremely disadvantageous and inappropriate for a customer that consists almost exclusively of residential load and can only recover residential rates, which are not subject to such ratchet requirements.

Q. Are there any other aspects of TEP's rebuttal filing on this topic to which you are responding?

A. Yes. TEP has "bootstrapped" an unrelated issue into its rebuttal filing, specifically a proposal to cut off frozen Senior Lifeline and frozen Medical Lifeline discounts to residents of master-metered mobile home parks after one year. According to Mr. Jones, TEP currently has contracts with 23 master-metered mobile home parks through which these Lifeline discounts are passed through in the bills TEP sends to the mobile home parks and which in turn are passed through to the eligible residents by the mobile home park operators.[19] Also according to Mr. Jones, some of these contracts have been in place for more than twenty years. The rationale offered by TEP for abandoning this longstanding arrangement is that because residents of master-metered mobile home parks are technically "not TEP customers," they should no longer be eligible for these Lifeline programs.

Q. What is your response to this proposal?

A. TEP's proposal is instructive in that it illustrates the extent to which the Company is willing to resort to the strong-arm tactics of a monopoly to have its way. Rather than agree to allow a handful of mobile home parks that are on the wrong rate schedule to migrate to the rate schedule designed for them, TEP has "doubled down" and taken aim to eliminate Lifeline discounts for the most vulnerable residents of master-metered mobile home parks. The proposal is harsh, ill-conceived, and discriminatory. The proposal should be rejected.

Q. Please summarize your recommendations concerning the Mobile Home Park rate schedule.

A. This issue is not complicated and requires a simple, straightforward solution. Currently, there are a handful of master-metered mobile home parks that are on the LGS rate schedule – a rate schedule with a significant demand charge and a 75% demand ratchet. This rate schedule is ill-suited for these customers because they are statutorily required to charge their residents TEP's residential

[19] Rebuttal Testimony of Craig A. Jones, p. 56.

rate – and the LGS rate design is a poor fit for customers with a residential load profile.

TEP has a Mobile Home Park rate schedule that is far more suitable for these customers, but TEP refuses to allow these customers to migrate to it because this rate schedule does not allow any "new" customers to join, including *existing* master-metered mobile home parks that happen to be on rate schedules other than the mobile home park rate. In this general rate case, TEP is proposing to modify the eligibility criteria for this rate schedule to state that it is "only available to premises *historically* served on a master metered mobile home park tariff" and that is it is "not available to new facilities." [Emphasis added.] So the newly-proposed language would have the same effect of preventing these customers from migrating to the Mobile Home Park rate.

The solution is simple and inconveniences no one. The applicability criteria for Mobile Home Park Electric Service – GS-11F should be amended to remove the restriction on service to new customers. Similarly, to the extent that TEP's proposed replacement rate schedule GS-M-F is adopted, the prohibition on "new facilities" should be removed, as it is superfluous and ambiguous, as R14-2-205 already requires a utility to refuse service to all new construction or expansion of permanent mobile home parks unless the construction or expansion is individually metered. Further, the applicability criteria should be amended to remove any language that restricts this rate schedule to premises that have been *historically* served on a master metered mobile home park tariff, as this restriction unreasonably prevents an otherwise eligible customer from switching to this rate schedule from a rate schedule that is ill-suited for the customer. At a minimum, the applicability criteria should be amended such that there is no restriction on migrating to this rate schedule for any existing master-metered mobile home park.

LOST FIXED COST RECOVERY MECHANISM

Q. In your direct testimony you recommended that TEP's proposed changes to the LFCR mechanism should be rejected. Have any of the arguments advanced by TEP in its rebuttal filing altered your recommendation?

A. No. In this proceeding TEP consistently fails to recognize that the existing LFCR mechanism is not based on a grand regulatory principle upon which all parties to this case (or the last case) agree, but is the product of a *compromise* in the last case among parties with very disparate views as to the merit (or lack thereof) of the LFCR. Having secured the compromise in the last case, TEP is now seeking to "perfect" the LFCR from the Company's vantage point by expanding the costs eligible for recovery though the LFCR mechanism to include generation and fixed must-run fixed costs, as well as the remaining 50% of demand charge revenue currently excluded from the calculation. Further, TEP proposes to increase the year-over-year cap from 1% to 2% due to the proposed expansion of LFCR-eligible costs.

As I explained in my Direct Testimony, I am not persuaded that an LFCR is needed in the first instance, and I particularly disagree with levying this charge on LGS customers, as a significant part of TEP's concern regarding these customers can be addressed through rate design. Therefore, not only do I disagree with TEP's proposed changes, but I also recommend that LGS customers be exempted from this charge going forward. In my Direct Testimony, I explained that a significant part of TEP's concern regarding LGS customers can be addressed through rate design.

Q. **On pages 55 to 56 of his Rebuttal Testimony, Mr. Jones takes issue with the statement in your Direct Testimony that exclusion of the LGS class from the LFCR would not shift costs to other classes for recovery. How do you respond?**

A. Mr. Jones is incorrect. As I stated in my Direct Testimony, if a customer group is excluded from the LFCR mechanism, they would neither pay the LFCR *nor shift costs to other classes for recovery.* The only LFCR costs that should be recorded by TEP would be those directly attributable to the participating classes. Consequently, no costs would be shifted from non-participants to participants. This statement in my Direct Testimony is entirely correct.

Mr. Jones takes issue with my statement and states that I seem "to mischaracterize how lost fixed costs are shifted to the other customer classes" if my recommendation to exclude LGS customers is approved. Mr. Jones then goes on to argue that since the LGS class benefits from DG and EE-related programs, it "generates lost revenues." Mr. Jones then concludes that, "if they are excluded from the LFCR, those lost revenues would most definitely be shifted to other customer classes. [Mr. Higgins'] statement is not correct."[20]

It is Mr. Jones who is incorrect on this point, as his assertions are inconsistent with how the LFCR Plan of Administration ("POA") works. The LPS, water pumping, and lighting rate schedules are already expressly excluded from the LFCR mechanism in the POA, which clearly states that Applicable

[20] Id., pp. 56-57.

Company Revenues, Distributed Generation ("DG") Savings, and Energy Efficiency ("EE") Savings are each excluded from the LFCR calculation for the excluded classes. Consequently, the POA ensures that no DG or EE savings attributed to the excluded rate schedules are included in the LFCR revenues that are recovered from the remaining customers. If LGS were included in the list of excluded rate schedules, as I propose, then the same principle would apply: no costs would be shifted from non-participants to participants.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Q. In your Direct Testimony you recommended the adoption of a risk-sharing mechanism in the PPFAC. Is that still your recommendation?

A. Yes. The other western states of Wyoming, Oregon, Washington, Idaho, and Montana each have sharing mechanisms in their fuel adjustors, through which customers and shareholders share in the risks and benefits of deviations in fuel costs in between rate cases, rather than simply passing though 100% of all cost deviations to customers as TEP does. A risk-sharing mechanism provides a utility with proper incentives to produce the greatest possible net benefit to its customers from the operations of its system and is essential to keep customer and shareholder interests aligned. This incentive is most efficiently implemented through a mechanism in which the utility shares in the benefits and risks of its decisions. I continue to encourage the Commission to adopt a 70% customer/30% utility sharing provision, similar to what is approved in Wyoming, rather than retaining the current 100/0 approach.

Q. What has been TEP's response to your proposal?

A. TEP is opposed to my proposal. TEP witness Ramondo J. Robey argues that I have provided no evidence that TEP is not utilizing prudent utility practices in the way the Company currently manages the dispatch of its generation fleet. Mr. Robey also avers that adoption of my proposal would incentivize TEP into viewing its hedging activities more in line with that of speculative trading activities.[21] Finally, Mr. Robey challenges my characterization of the Wyoming 70/30 sharing mechanism, which he depicts as being only a test of the utility's forecast, rather than a determination of the utility's prudent behavior.[22]

Q. What is your response to Mr. Robey's argument that you have not provided evidence of imprudent behavior on TEP's part?

A. I appreciate that utilities generally prefer that regulators rely on the high bar of a imprudence finding when it comes to determining the recovery of fuel costs in between rate cases, but as I explained in my Direct testimony, the threat of a finding of imprudence following an after-the-fact audit is not a good substitute for a utility having "skin in the game" when it comes to managing its fuel costs. A finding of imprudence essentially requires a determination that a utility acted unreasonably in its power cost management. In contrast, a risk-sharing mechanism structured such that each and every transaction affects the Company's bottom line, provides an incentive for the Company to get the *best possible deal* from every transaction. Striving to get the best possible deal from every transaction is different from simply not behaving unreasonably. Getting the

[21] Rebuttal Testimony of Ramondo J. Robey, pp. 7-8.
[22] Id., pp. 8-9.

best possible deal is a more exacting and efficient aspiration. A well-crafted sharing mechanism supports this objective.

Q. What about Mr. Robey's claim that a risk-sharing mechanism would incentivize TEP to become a speculator?

A. This argument is unpersuasive and should be rejected. The utilities that are subject to risk-sharing mechanisms also adhere to hedging protocols. Obviously, TEP prefers that the only parties to be impacted by TEP's hedging practices are its customers. However, there is nothing wrong with both customers and shareholders sharing in the consequences of the Company's hedging decisions in between rate cases. In fact, I believe it is preferable for both parties to share in the benefits and costs of these decisions.

Q. What is your response to Mr. Robey's characterization of the 70/30 sharing mechanism in Wyoming?

A. I was a witness in both Wyoming cases in which the 70/30 sharing mechanism was considered and adopted. Mr. Robey's description of the 70/30 sharing mechanism in Wyoming is inaccurate. Mr. Robey depicts the sharing mechanism as being applied only to variances between actual fuel costs and the utility's fuel *forecasts*. That is not the case at all. The Wyoming sharing mechanism is applied through its fuel adjustor, or ECAM,[23] to the variance between the utility's fuel and net purchased power costs *in rates* (as approved in a general rate case) and the utility's *actual* fuel and net purchased power costs. As such, the Wyoming ECAM requires a sharing between customers and shareholders of the deviations in actual fuel and purchased power costs (called

[23] ECAM stands for Energy Cost Adjustment Mechanism.

"net power costs") relative to the net power costs that are in rates. Further, the Wyoming sharing mechanism was adopted specifically to provide good incentives for the utility to manage its costs as effectively as possible. As stated in the Wyoming Public Service Commission's decision:

> The Company proposed several changes to its ECAM. RMP wants to eliminate the 70/30 sharing band, claiming that the sharing band serves no purpose and results in denial of recovery of prudently incurred power costs. However, we find, based on the testimony from the other parties that the sharing band has and will continue to incent RMP to improve its forecasts of base [net power costs] *as well as to control other [net power cost] costs.*[24]

This decision was not based on any finding of imprudence or mismanagement, but rather is based on aligning the interests of customers and the utility in management of the utility's fuel and purchased power costs.

Q. In your Direct Testimony you also proposed a change in the way the margins from new long-term sales contracts are treated in the PPFAC. Is that still your position?

A. Yes. In my Direct Testimony I explained that prior to the last general rate case, the margins from all wholesale transactions, irrespective of the duration of the contract, were credited to customers in the PPFAC, except for the margins from those long-term contracts that were used in the calculation of the jurisdictional demand allocation. The exclusion of these latter margins made sense because those long-term contracts were allocated a share of system production demand costs. But the general proposition that *all other margins* – whether from short-term sales or long-term sales – should be credited to

[24] *See* Wyoming Public Service Commission, Docket No. 20000-469-ER-15, Memorandum Opinion, Findings of Fact, Decision and Order, December 30, 2015, at Paragraph 79. Emphasis added.

customers through the PPFAC also made sense because these sales are made using assets that are paid for by customers.

However, the 2013 Settlement Agreement approved in the last general rate case incorporated a TEP proposal to change the PPFAC POA in a way that assigned 100% of the margins from new contracts longer than one year to the benefit of shareholders rather than customers. While this provision was acceptable as part of the 2013 settlement package, it is unreasonable in the context of the current general rate case and should not be extended.

If a long-term sales contract is not assigned fixed production cost responsibility in the determination of inter-jurisdictional demand allocation, then the margins from those sales should be credited to customers in the same proportion as any sharing mechanism generally applicable to the fuel adjustor. So, for example, under the current PPFAC, which has no sharing mechanism, 100% of the margins from new long-term contracts that go into effect in between rate cases properly should be credited to customers, because such new long-term contracts would not be allocated any demand costs in the preceding general rate case. By the same token, if a 70/30 PPFAC sharing mechanism is adopted, then 70% of the margins should be credited to customers, consistent with the split of the overall sharing mechanism.

Q. How has TEP responded to your proposal to return to the prior practice of crediting the margins from new long-term contracts to customers?

A. Mr. Robey opposes my recommendation. However, Mr. Robey's explanation for TEP's opposition demonstrates some confusion as to what my proposal actually is. His stated reason for opposition is that long-term wholesale contracts are allocated a percentage of non-fuel costs.[25] The problem with this response is that my proposal is not directed toward those long-term contracts that are allocated a percentage of non-fuel costs in a general rate case. My proposal is directed to new long-term contracts that are not included in the cost allocation. Flowing 100% of the margins to TEP from such new contracts that are not allocated any non-fuel costs creates an undeserved windfall for TEP. This is the circumstance that needs to be rectified going forward. As I stated in my Direct Testimony, in general, all revenues from wholesale sales, irrespective of term, should be credited against fuel and purchased power costs and included in the PPFAC, unless such sales are allocated a share of system costs. Consequently, the change in the POA approved in the last general rate case that shifted all the benefits from new long-term contracts from customers to shareholders should be reversed.

MOVEMENT OF ENERGY EFFICIENCY CHARGES INTO BASE RATES

Q. Have you reviewed the proposal of SWEEP witness Jeff Schlegel to include $23 million of energy efficiency program costs in base rates?

A. Yes, I have. Mr. Schlegel argues that as a "core resource," it is appropriate for energy efficiency cost recovery to be in base rates rather than in the separate adjustor mechanism. Mr. Schlegel then goes on to propose that the DSM surcharge mechanism should remain intact, but be used as an adjustor to

[25] Rebuttal Testimony of Ramondo J. Robey, p. 12.

recover any energy efficiency funding amounts above or below the $23 million he proposes be included in base rates.[26]

Q. What is your response to this recommendation?

A. I recommend that Mr. Schlegel's proposal be denied. Energy efficiency program costs should not be shifted from the DSM Surcharge into base rates. The shifting of costs from the DSM Surcharge costs into base rates would result in a loss of transparency regarding the cost of the Company's energy efficiency programs. This information should not be hidden from customers.

Currently, TEP's DSM Surcharge is set at 1.97% of a non-residential customer's bill. This rate design provides simple and straightforward information to customers regarding the cost of the TEP's energy efficiency programs in relation to the customer's total bill. It also provides for an efficient and equitable means to recover these costs. This useful construct would be disrupted if Mr. Schlegel's proposal were adopted.

The shifting of energy-efficiency program costs and incentives into base rates – while retaining a DSM Surcharge – creates a potential for misinterpretation. Specifically, the proposed change could cause customers to mistakenly believe that the costs of the Company's DSM programs and incentives are limited to those costs that appear in the surcharge. Erroneous inferences of this sort should be avoided. Public policy should err on the side of disclosure and transparency.

Q. Do you have other concerns regarding Mr. Schlegel's proposal?

[26] Direct Testimony of Jeff Schlegel, pp. 8-9.

A. Yes. One of the most significant remaining issues in this case is revenue allocation among customer classes and the challenge of gradually eliminating the significant cross subsidies among customer classes in TEP's current rate structure. Currently, the allocation of energy efficiency costs is not part of that problem, however, because these costs are already equitably allocated through the design of the DSM surcharge. But moving the costs from the surcharge into base rates would undo the equitable cost allocation achieved through the DSM surcharge and would likely add to the problem of trying to attain base rate parity.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

KCH-SR-1

AECC/Noble Solutions Recommended Unbundled LPS-TOU & 138kV Rates at AECC/Noble Solutions Rate Spread & Settlement Revenue Requirement

Line No.	Description	LPS-TOU AECC/ Noble Solutions Recommended	LPS-138kV AECC/ Noble Solutions Recommended
	(a)	(b)	(c)
1	Basic Service Charge Components ($/Cust./Mo.):		
2	Meter Services	$488.53	$348.37
3	Meter Reading	$8.19	$82.10
4	Billing & Collection	$149.70	$1,228.02
5	Customer Delivery	$1,353.58	$1,341.51
6	Total	$2,000.00	$3,000.00
7	Demand Charge Components ($/kW):		
8	Local Delivery (See Note 1)		
9	Summer On-Peak	$3.97	$0.01
10	Summer Off-Peak	$1.62	$0.01
11	Winter On-Peak	$2.74	$0.01
12	Winter Off-Peak	$0.69	$0.01
13	Generation Capacity		
14	Summer On-Peak	$8.76	$7.58
15	Summer Off-Peak	$3.58	$3.72
16	Winter On-Peak	$6.05	$5.71
17	Winter Off-Peak	$1.51	$1.19
18	Fixed Must-Run	$1.50	$1.47
19	Transmission Components (See Note 2):		
20	FERC Transmission Rate	$3.39	$3.23
21	Ancillary 1: System Control & Dispatch	$0.05	$0.04
22	Ancillary 2: Reactive Supply & Voltage Control	$0.18	$0.17
23	Ancillary 3: Regulatory & Freq Response	$0.18	$0.17
24	Ancillary 4: Spinning Reserve Service	$0.48	$0.45
25	Ancillary 5: Supplemental Reserve Service	$0.08	$0.07
26	Total Transmission	$4.36	$4.13
27	Total Demand Charges ($/kW):		
28	Summer On-Peak	$18.59	$13.19
29	Summer Off-Peak	$11.06	$9.33
30	Winter On-Peak	$14.65	$11.32
31	Winter Off-Peak	$8.06	$6.80
32	Generation Energy Charge Components ($/kWh):		
33	Summer On-Peak	$0.00780	$0.00780
34	Summer Off-Peak	$0.00780	$0.00780
35	Winter On-Peak	$0.00780	$0.00780
36	Winter Off-Peak	$0.00780	$0.00780
37	Power Supply Charges ($/kWh):		
38	Base Power Supply Charges		
39	Base Power Supply Summer On-Peak	$0.049077	$0.048044
40	Base Power Supply Summer Off-Peak	$0.025413	$0.024878
41	Base Power Supply Winter On-Peak	$0.032198	$0.031520
42	Base Power Supply Winter Off-Peak	$0.026687	$0.026126

Notes:

1. AECC/Noble Solutions Unbundled Delivery demand charge is designed such that the combination of Basic Service Charge and Delivery demand charge revenues are proportionate to Distribution costs. AECC/Noble Solutions eliminated the Delivery energy charges (re-designated as Generation energy charges).

2. AECC/Noble Solutions Unbundled Transmission component calculation utilized the general approach used in TEP's Direct Filing. However, AECC calculated the LPS and 138 kV Transmission components separately, based upon TEP's rebuttal transmission expense workpaper, 2015 TEP TransExp CompSensConfid Rebuttal.

AECC/Noble Solutions Recommended Unbundled LGS Rates at AECC/Noble Solutions Rate Spread & Settlement Revenue Requirement

Line No.	Description	LGS AECC/ Noble Solutions Recommended
	(a)	(b)
1	Basic Service Charge Components ($/Cust./Mo.):	
2	Meter Services	$157.10
3	Meter Reading	$2.58
4	Billing & Collection	$48.68
5	Customer Delivery	$741.64
6	Total	$950.00
7	Demand Charge Components ($/kW):	
8	Delivery Charge (See Note 1)	$1.97
9	Generation Capacity	$13.10
10	Fixed Must-Run	$1.64
11	Total Transmission (See Note 2)	$4.36
12	Total Demand Charge	$21.07
13	Transmission Charge Components ($/kW):	
14	FERC Transmission Rate	$3.39
15	Ancillary 1: System Control & Dispatch	$0.05
16	Ancillary 2: Reactive Supply & Voltage Control	$0.18
17	Ancillary 3: Regulatory & Freq Response	$0.18
18	Ancillary 4: Spinning Reserve Service	$0.48
19	Ancillary 5: Supplemental Reserve Service	$0.08
20	Total Transmission	$4.36
21	Energy Charge Components ($/kWh):	
22	Local Delivery - Summer	$0.00000
23	Local Delivery - Winter	$0.00000
24	Base Power Supply Charges ($/kWh):	
25	Base Power Supply Summer	$0.035868
26	Base Power Supply Winter	$0.032537

Notes:

1. AECC/Noble Solutions Unbundled Delivery demand charge is designed such that the combination of Basic Service Charge and Delivery demand charge revenues are proportionate to Distribution costs.

2. AECC/Noble Solutions Unbundled Transmission component calculation utilized the general approach used in TEP's Direct Filing, updated for TEP's rebuttal transmission expense workpaper, 2015 TEP TransExp CompSensConfid Rebuttal.

Functional Cost Alignment of AECC/Noble Solutions Proposed Unbundled Rates at AECC/Noble Solutions Rate Spread & Settlement Revenue Requirement Combined LPS-TOU and 138 kV Classes

Line No.	Description	LPS-TOU & 138 kV Total Costs at TEP's Direct Proposed Revenue Requirement[1]	Proportion of Total Gen. & Dist. Costs	LPS-TOU & 138 kV Revenue from AECC/Noble Solutions Recommended Rates[2]	Proportion of Total Gen. & Dist. Revenue[3]
	(a)	(b)	(c)	(d)	(e)
1	Distribution (Demand and Customer)	$9,229,567	16.4%	$8,117,069	16.4%
2	Generation Capacity[4]	$41,705,268	74.3%	$36,662,004	74.2%
3	Fixed Must-Run	$5,224,566	9.3%	$4,609,960	9.3%
4	Total Distribution & Generation Costs	$56,159,401	100.0%	$49,389,033	100.0%
5	Transmission[5]	$11,691,029		$13,293,195	
6	Power Supply	$53,594,957		$53,594,957	
7	Total - All Functions	$121,445,387		$116,277,186	
8	Other Revenue Credit	-$2,161,104			
9	Net Cost to be Collected from Sales Revenue[6]	$119,284,283			

Notes:
1. Based on AECC/Noble Solutions surrebuttal class cost-of-service study at TEP's Direct proposed revenue requirement.
2. Revenues resulting from AECC's surrebuttal proposed Unbundled rates, reflecting AECC's proposed rate spread and the Settlement revenue requirement.
3. Differences between Col. (e) and Col. (c) are due to rate rounding.
4. Power Factor revenues, as well as AECC/Noble Solutions Generation energy charge of $0.0078/kWh, are considered Generation Capacity-related.
5. AECC/Noble Solutions Unbundled Transmission component calculation utilized the general approach used in TEP's Direct Filing, updated for TEP's rebuttal transmission expense workpaper, 2015 TEP TransExp CompSensConfid Rebuttal.

KCH-SR-2

Comparison of Average Residential Rates and Rates Paid by a Hypothetical Mobile Home Park Customer on Schedule LGS-13

Average Monthly Summer Demand = 400 kW
Average Monthly Non-Summer Demand = 200 kW

TEP Residential Rate Schedule	Current TE-R-01 Rates	TE-R-01 Service Billing Determinants	Revenues
Residential Service (TE-R-01)			
Basic Service Charge Single Phase Per Mo.	$10.00	4,175,628	$41,756,280
Basic Service Charge Three Phase Per Mo.	$15.00	3,442	$51,624
Sum First 500 kWh	$0.056200	762,703,189	$42,863,919
Sum 501-1,000 kWh	$0.067200	503,607,184	$33,842,403
Sum 1,001-3,500 kWh	$0.079800	518,920,086	$41,409,823
Sum>3,500 kWh	$0.088200	16,585,028	$1,462,799
Win First 500 kWh	$0.056200	929,496,499	$52,237,703
Win 501-1,000 kWh	$0.065200	367,506,796	$23,961,443
Win 1,001-3,500 kWh	$0.078100	177,513,099	$13,863,773
Win>3,500 kWh	$0.087100	4,632,713	$403,509
Miscellaneous Revenue			(45,552)
Subtotal Delivery Revenue			$251,807,725
Base Power Summer kWh	$0.035111	1,801,815,486	$63,263,544
Base Power Winter kWh	$0.031532	1,479,149,108	46,640,530
PPFAC Revenue	$0.003892	3,280,964,594	12,770,210
Subtotal Fuel Revenue			$122,674,283
Surcharges			
LFCR - EE	1.2068%		$4,519,249
LFCR - DG	0.4406%		$1,649,968
ECA	$0.000250		$820,241
REST	$0.013000		$42,652,540
DSM	$0.001916		$6,286,328
Subtotal Surcharges:			$55,928,326
Total Estimated Revenues:			$430,410,334
Average $ per kWh:			$\boxed{\$0.1312}$

Hypothetical Mobile Home Park Customer	Current Rates TE-LGS-13 Rates	Customer Billing Determinants	Revenues
Large General Service (TE-LGS-13)			
Basic Service Charge Per Month	$775.00	12	$9,300
Demand Charge Per kW	$15.25	4,100	$62,525
Summer kWh	$0.0192	563,059	$10,811
Winter kWh	$0.0134	338,312	$4,533
Subtotal Delivery Revenue			$87,169
Base Power Summer kWh	$0.035111	563,059	$19,770
Base Power Winter kWh	$0.031532	338,312	10,668
PPFAC Revenue	$0.003892	901,371	3,508
Subtotal Fuel Revenue			$33,946
Surcharges			
LFCR	1.2068%		$1,462
LFCR	0.4406%		$534
ECA	$0.000250		$225
REST	$0.013000		$11,718
DSM	1.97%		$2,386
Subtotal Surcharges:			$16,324
Total Estimated Revenues:			$137,439
Average $ per kWh:			$\boxed{\$0.1525}$

Data Sources:
1. Schedule H-5, Page 1, Bill Count
2. 2015 TEP Revenue Proof - Public

AECC'S DEPICTION OF TEP'S RECOMMENDED CHANGE IN CLASS REVENUES

TEP REJOINDER RECOMMENDED SPREAD COMPARED TO PRESENT REVENUES DERIVED BY APPLYING CURRENT 2016 MARGIN AND FUEL RATES TO POST-MIGRATION LOAD

Line No.	Customer Class	AECC Present Margin Revenue[1]	AECC Present Fuel Revenue[1]	AECC Present Sales Revenue[1]	TEP Proposed Margin Revenue[2]	TEP Proposed Fuel Revenue[2]	TEP Proposed Sales Revenue[2]	Proposed Margin $ Change	Proposed Fuel $ Change	Proposed Sales $ Change	Proposed Sales % Change
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g) = (e) + (f)	(h) = (e) - (b)	(i) = (f) - (c)	(j) = (g) - (d)	(k) = (j) ÷ (d)
1	Residential	$275,887,975	$126,680,899	$402,568,874	$327,768,312	$122,880,261	$450,648,573	$51,880,337	($3,800,638)	$48,079,699	11.9%
2	General Service	158,361,904	63,527,307	221,889,211	180,501,853	62,408,888	242,910,741	22,139,949	(1,118,419)	21,021,530	9.5%
3	Large General Service	94,708,262	49,659,855	144,368,117	96,255,565	48,879,589	145,135,154	1,547,303	(780,266)	767,038	0.5%
4	Total LPS (TOU & 138kV)	68,538,230	53,443,343	121,981,574	73,582,355	53,707,795	127,290,150	5,044,125	264,451	5,308,576	4.4%
5	Large Power Service	51,975,049	39,539,694	91,514,743	56,404,499	39,823,018	96,227,517	4,429,450	283,324	4,712,774	5.1%
6	High Voltage 138kV	16,563,181	13,903,649	30,466,830	17,177,856	13,884,777	31,062,633	614,675	(18,873)	595,803	2.0%
7	Lighting	3,298,783	1,339,429	4,638,212	4,211,298	1,312,824	5,524,123	912,515	(26,604)	885,911	19.1%
8	Total	$600,795,154	$294,650,833	$895,445,987	$682,319,384	$289,189,357	$971,508,741	$81,524,230	($5,461,476)	$76,062,754	8.5%

Data Sources:
1. AECC/Noble Solutions Adjusted Present Revenue workpaper.
2. TEP Witness Craig Jones Rejoinder Testimony, Exhibit CAJ-RJ-1, Sch. H-2-2.

Table Definitions
1. AECC "Current" Margin Revenue = AECC's derivation of margin revenue at present 2016 margin rates applied to TEP's post-migration loads (which includes the projected reduction in 138kV load).
2. AECC "Current" Fuel Revenue = AECC's derivation of fuel revenue at present 2016 fuel rates (with PPFAC = $0.01501/kWh) applied to post-migration loads (which includes the projected reduction in 138 kV loads).
3. TEP "Proposed" Margin Revenue = TEP's derivation of margin revenue at proposed margin rates applied to TEP's post-migration loads (which includes the projected reduction in 138 kV loads).
4. TEP "Proposed" Fuel Revenue = TEP's derivation of fuel revenue at proposed 2017 fuel rates applied to post-migration loads (which includes the projected reduction in 138 kV loads).

TEP'S DEPICTION OF ITS RECOMMENDED CHANGE IN CLASS REVENUES

TEP REJOINDER RECOMMENDED SPREAD - PRESENT MARGIN REVENUES BEFORE MIGRATION (EXCEPT 138 kV) WITH PROFORMA FUEL REVENUE

Line No.	Customer Class	TEP Present Margin Revenue[1]	TEP Proforma Fuel Revenue[1]	TEP "Present" Sales Revenue[1]	TEP Proposed Margin Revenue[1]	TEP Proposed Fuel Revenue[1]	TEP Proposed Sales Revenue[1]	Proposed Margin $ Change[1]	Proposed Fuel $ Change[1]	Proposed Sales $ Change[1]	Proposed Sales % Change[1]
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g) = (e) + (f)	(h) = (e) - (b)	(i) = (f) - (c)	(j) = (g) - (d)	(k) = (j) ÷ (d)
9	Residential	$275,887,975	$122,880,261	$398,768,236	$327,768,312	$122,880,261	$450,648,573	$51,880,337	$0	$51,880,337	13.0%
10	General Service	184,448,887	62,408,888	246,857,775	180,501,853	62,408,888	242,910,741	(3,947,034)	0	(3,947,034)	-1.6%
11	Large General Service	68,460,569	48,879,589	117,340,158	96,255,565	48,879,589	145,135,154	27,794,996	0	27,794,996	23.7%
12	Total LPS (TOU & 138kV)	68,722,998	53,707,795	122,430,793	73,582,355	53,707,795	127,290,150	4,859,357	0	4,859,357	4.0%
13	Large Power Service	52,159,816	39,823,018	91,982,834	56,404,499	39,823,018	96,227,517	4,244,682	0	4,244,682	4.6%
14	High Voltage 138kV	16,563,182	13,884,777	30,447,958	17,177,856	13,884,777	31,062,633	614,675	0	614,675	2.0%
15	Lighting	3,298,783	1,312,824	4,611,607	4,211,298	1,312,824	5,524,123	912,515	0	912,515	19.8%
16	Total	$600,819,212	$289,189,357	$890,008,569	$682,319,384	$289,189,357	$971,508,741	$81,500,172	$0	$81,500,172	9.2%

Data Sources:
1. TEP Witness Craig Jones Rejoinder Testimony, Exhibit CAJ-RJ-1, Sch. H-2-2 (Present Revenue Before Migration except 138kV with Proforma Fuel).

Table Definitions
1. TEP "Current" Margin Revenue = TEP's derivation of margin revenue at present 2016 margin rates applied to TEP's *pre-migration* loads (except for 138kV migration which includes the projected reduction in 138kV load).
2. TEP "Current" Fuel Revenue = TEP's derivation of fuel revenue at present 2017 fuel rates applied to post-migration loads (which includes the projected reduction in 138 kV loads).
3. TEP "Proposed" Margin Revenue = TEP's derivation of margin revenue at proposed margin rates applied to TEP's post-migration loads (which includes the projected reduction in 138 kV loads).
4. TEP "Proposed" Fuel Revenue = TEP's derivation of fuel revenue at proposed 2017 fuel rates applied to post-migration loads (which includes the projected reduction in 138 kV loads).

EXHIBIT
AECC-12
ADMITTED

AECC'S RECOMMENDED CHANGE IN CLASS REVENUES [EXCLUDING AECC'S PROPOSED BUY-THROUGH ADJUSTMENT]

AECC SURREBUTTAL RECOMMENDED SPREAD - PRESENT REVENUES AFTER MIGRATION WITH PRESENT FUEL REVENUE (PPFAC = 0.001501/kWh)

Line No.	Customer Class	AECC Present Margin Revenue[1]	AECC Present Fuel Revenue[1]	AECC Present Sales Revenue[1]	AECC Proposed Margin Revenue[2]	AECC Proposed Fuel Revenue[2]	AECC Proposed Sales Revenue[2]	AECC Proposed Margin $ Change	AECC Proposed Fuel $ Change	AECC Proposed Sales $ Change	AECC Proposed Sales % Change
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g) = (e) + (f)	(h) = (e) - (b)	(i) = (f) - (c)	(j) = (g) - (d)	(k) = (j) ÷ (d)
1	Residential	$275,887,975	$126,680,899	$402,568,874	$352,570,805	$123,295,676	$475,866,481	$76,682,831	($3,385,223)	$73,297,608	18.2%
2	General Service	158,361,904	63,527,307	221,889,211	175,896,150	62,333,560	238,229,710	17,534,246	(1,193,748)	16,340,499	7.4%
3	Large General Service	94,708,262	49,659,855	144,368,117	86,738,121	48,652,888	135,391,010	(7,970,140)	(1,006,966)	(8,977,107)	-6.2%
4	Total LPS (TOU & 138kV)	68,538,230	53,443,343	121,981,574	62,690,481	53,594,957	116,285,438	(5,847,749)	151,614	(5,696,135)	-4.7%
5	Large Power Service	51,975,049	39,539,694	91,514,743	49,759,191	39,670,890	89,430,081	(2,215,858)	131,196	(2,084,662)	-2.3%
6	High Voltage 138kV	16,563,181	13,903,649	30,466,830	12,931,290	13,924,067	26,855,357	(3,631,891)	20,418	(3,611,473)	-11.9%
7	Lighting	3,298,783	1,339,429	4,638,212	4,399,465	1,314,137	5,713,602	1,100,681	(25,291)	1,075,390	23.2%
8	Total	$600,795,154	$294,650,833	$895,445,987	$682,295,023	$289,191,218	$971,486,241	$81,499,869	($5,459,614)	$76,040,254	8.5%

Data Sources:
1. AECC/Noble Solutions Adjusted Present Revenue workpaper.
2. Data Source: AECC witness Kevin C. Higgins Surrebuttal Testimony, p. 18 [Table KCH-SR-2 (CONFIDIENTIAL)].

Table Definitions
1. AECC "Current" Margin Revenue = AECC's derivation of margin revenue at present 2016 margin rates applied to TEP's post-migration loads (which includes the projected reduction in 138kV load).
2. AECC "Current" Fuel Revenue = AECC's derivation of fuel revenue at present 2016 fuel rates (with PPFAC = $0.01501/kWh) applied to post-migration loads (which includes the projected reduction in 138 kV loads).
3. AECC "Proposed" Margin Revenue = AECC's derivation of margin revenue determined using TEP's post-migration loads (which includes the projected reduction in 138 kV loads).
4. AECC "Proposed" Fuel Revenue = AECC's derivation of fuel revenue at proposed 2017 fuel rates applied to post-migration loads (which includes the projected reduction in 138 kV loads).

AECC'S DEPICTION OF STAFF'S RECOMMENDED CHANGE IN CLASS REVENUES

STAFF SURREBUTTAL RECOMMENDED SPREAD - PRESENT REVENUES AFTER MIGRATION WITH PRESENT FUEL REVENUE (PPFAC = 0.001501/kWh)

Line No.	Customer Class	AECC Present Margin Revenue[1]	AECC Present Fuel Revenue[1]	AECC Present Sales Revenue[1]	Staff Proposed Margin Revenue[2]	Staff Proposed Fuel Revenue[2]	Staff Proposed Sales Revenue[2]	Staff Proposed Margin $ Change	Staff Proposed Fuel $ Change	Staff Proposed Sales $ Change	Staff Proposed Sales % Change
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g) = (e) + (f)	(h) = (e) - (b)	(i) = (f) - (c)	(j) = (g) - (d)	(k) = (j) ÷ (d)
1	Residential	$275,887,975	$126,680,899	$402,568,874	$330,389,025	$123,295,676	$453,684,701	$54,501,050	($3,385,223)	$51,115,827	12.7%
2	General Service	158,361,904	63,527,307	221,889,211	173,782,573	62,333,560	236,116,132	15,420,669	(1,193,748)	14,226,921	6.4%
3	Large General Service	94,708,262	49,659,855	144,368,117	97,778,732	48,886,253	146,664,985	3,070,470	(773,602)	2,296,868	1.6%
4	Total LPS (TOU & 138kV)	68,538,230	53,443,343	121,981,574	76,454,574	53,385,302	129,839,877	7,916,344	(58,041)	7,858,303	6.4%
5	Large Power Service	51,975,049	39,539,694	91,514,743	57,892,333	40,021,120	97,913,453	5,917,284	481,426	6,398,710	7.0%
6	High Voltage 138kV	16,563,181	13,903,649	30,466,830	18,562,241	13,364,182	31,926,423	1,999,060	(539,467)	1,459,593	4.8%
7	Lighting	3,298,783	1,339,429	4,638,212	3,890,251	1,314,137	5,204,388	591,468	(25,291)	566,176	12.2%
8	Total	$600,795,154	$294,650,833	$895,445,987	$682,295,154	$289,214,928	$971,510,083	$81,500,000	($5,435,904)	$76,064,096	8.5%

Data Sources:
1. AECC/Noble Solutions Adjusted Present Revenue workpaper.
2. Data Source: Staff Witness Howard Solganik Surrebuttal Testimony, Exhibit HS-6 & HS-6 workpaper (Confidential).
[Note: AECC has modified Staff's Proposed GS, LGS, LPS & 138 kV Sales Revenue to capture the impact of adjustments to current revenues to reflect the impact of load migration among classes]

Table Definitions
1. AECC "Current" Margin Revenue = AECC's derivation of margin revenue at present 2016 margin rates applied to TEP's post-migration loads (which includes the projected reduction in 138kV load).
2. AECC "Current" Fuel Revenue = AECC's derivation of fuel revenue at present 2016 fuel rates (with PPFAC = $0.01501/kWh) applied to post-migration loads (which includes the projected reduction in 138 kV loads).
3. Staff "Proposed" Margin Revenue = Staff's recommended class increase added to present revenues determined using *pre-migration* loads. AECC has modified Staff's Proposed GS, LGS, LPS & 138 kV Margin/Sales Revenue to capture the impact of migration adjustments to present revenues to reflect the impact of post-migration load among classes (which includes the projected reduction in 138kV load).
4. Staff "Proposed" Fuel Revenue = TEP's derivation of fuel revenue at proposed 2017 fuel rates applied to post-migration loads (which includes the projected reduction in 138 kV loads).

STAFF'S DEPICTION OF ITS RECOMMENDED CHANGE IN CLASS REVENUES

STAFF SURREBUTTAL RECOMMENDED SPREAD - PRESENT REVENUES BEFORE MIGRATION (EXCEPT 138kV) WITH "PRESENT" FUEL REVENUE (PPFAC VARIES)

Line No.	Customer Class	Staff Present Margin Revenue[1]	Staff "Present" Fuel Revenue[1]	Staff "Present" Sales Revenue[1]	Staff Proposed Margin Revenue[1]	Staff Proposed Fuel Revenue[1]	Staff Proposed Sales Revenue[1]	Staff Proposed Margin $ Change	Staff Proposed Fuel $ Change	Staff Proposed Sales $ Change	Staff Proposed Sales % Change
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f)	(g) = (e) + (f)	(h) = (e) - (b)	(i) = (f) - (c)	(j) = (g) - (d)	(k) = (j) ÷ (d)
9	Residential	275,887,975	135,724,786	411,612,761	330,389,025	123,295,676	453,684,701	54,501,050	(12,429,110)	42,071,940	10.2%
10	General Service	184,448,887	78,695,943	263,144,831	199,869,556	62,333,560	262,203,115	15,420,669	(16,362,384)	(941,715)	-0.4%
11	Large General Service	68,460,569	43,017,444	111,478,013	71,531,039	48,886,253	120,417,292	3,070,470	5,868,809	8,939,279	8.0%
12	Total LPS (TOU & 138kV)	73,302,768	62,844,076	136,146,844	81,219,112	53,385,302	134,604,414	7,916,344	(9,458,774)	(1,542,430)	-1.1%
13	Large Power Service	54,675,285	43,645,373	98,320,659	60,592,569	40,021,120	100,613,690	5,917,284	(3,624,253)	2,293,031	2.3%
14	High Voltage 138kV	18,627,483	19,198,703	37,826,185	20,626,543	13,364,182	33,990,725	1,999,060	(5,834,520)	(3,835,461)	-10.1%
15	Lighting	3,298,783	1,459,034	4,757,818	3,890,251	1,314,137	5,204,388	591,468	(144,897)	446,570	9.4%
16	Total	605,398,982	321,741,284	927,140,266	686,898,982	289,214,928	976,113,911	81,500,000	(32,526,356)	48,973,644	5.3%

1. Data Source: Staff Witness Howard Solganik Surrebuttal Testimony, Exhibit HS-6 & HS-6 workpaper (Confidential).

Table Definitions
1. Staff "Current" Margin Revenue = TEP's derivation of margin revenue at present 2016 margin rates applied to TEP's *pre-migration loads* (except for Staff's estimated 138kV migration impact which excludes the projected reduction in the 138kV load).
2. Staff "Current" Fuel Revenue = TEP's derivation of fuel revenue at present 2016 fuel rates applied to *pre-migration annualized/weather normalized loads* (except for Staff's estimated 138kV migration impact which excludes the projected reduction in the 138kV load).
3. Staff "Proposed" Margin Revenue = Staff's recommended class increase added to present revenues determined using *pre-migration* loads.
4. Staff "Proposed" Fuel Revenue = TEP's derivation of fuel revenue at proposed 2017 fuel rates applied to post-migration loads (which includes the projected reduction in 138 kV loads).

AECC-13

Economic Development Rate Tariff – Rate Discount
Rate Rider 13

Qualifications for Eligibility

EXHIBIT
AECC-13
ADMITTED

1. 1,000kW peak demand

2. 75% Load Factor

3. New or expanding business that build new facilities

4. New or expanding business that occupy existing vacant buildings.

5. Discount only applies to increased power portion of load.

6. Must also qualify under Qualified Facility Income Tax Credit (A.R.S. §41-1512) or Arizona quality jobs incentives (A.R.S. §41-1525)

7. A.R.S. §41-1525(A)

   "The owner of a business located in this state before **July 2017** is eligible for income tax credits under sections 43-1074 or 43-1161 or an insurance premium tax credit under section 20-224.03 for net increases in full-time employees residing in this state and hired in qualified employment positions in this state." [Emphasis added]

6. A.R.S. §41-1512(A)

   "...income tax credits are allowed for expanding or locating a **qualified facility** in this state pursuant to sections 43-1083.03 and 41-1164.04"

   Credit is computed by taking the lesser of: (i) the total qualifying investment in a qualified facility, or (ii) 200k for each net new full-time employment position at the qualified facility

   "qualified facility" means a facility in this state that devotes at least 80% of the property and payroll at the facility to one or more of the following:

   (a) Qualified manufacturing
   (b) Qualified headquarters
   (C) Qualified research

   "Qualified manufacturing" means manufacturing tangible products in this state if at least "65%" of the produce will be sold out-of –state.

“Manufacturing” means fabricating, producing or manufacturing raw or prepared materials into usable products, imparting new forms, qualities, properties and combinations.

“Qualified headquarters” means a global, national or regional headquarters for a taxpayer that is involved in manufacturing and that derives at least 65% of its revenue from out-of-state sales.

“Qualified research” has the same meaning in Section 41(d) of the internal revenue code – research must be conducted by a taxpayer involved in manufacturing that derives at least 65% of its revenue from out-of-state sales.

EXHIBIT
AECC-14
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Surrebuttal Testimony of Michael D. McElrath

on behalf of

Freeport Minerals Corporation

August 25, 2016

Q. PLEASE STATE YOUR NAME, AND BUSINESS ADDRESS.

A. Michael D. McElrath, 333 North Central Avenue, Phoenix Arizona.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Freeport Minerals Corporation ("Freeport") as its Director of Energy Services.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Freeport.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A. I have over 40 years of experience in the energy field beginning with 16 years with a natural gas utility with increasing responsibilities in 3 different states. I have worked in the mining industry for 28 years dealing with energy matters for 3 different mining companies. Today, I am responsible for the power and natural gas supplies for Freeport's mines in North America, South America and Africa.

Q. HAVE YOU TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (THE "COMMISSION") IN OTHER DOCKETS?

A. Yes. I have testified in a number of dockets before the Commission beginning in 1994.

Q. HAVE YOU TESTIFIED BEFORE ANY OTHER PUBLIC UTILITY COMMISSION?

A. Yes, I have testified before the Public Utility Regulatory Board in El Paso, Texas, the Public Utility Commission of Colorado and the Federal Energy Regulatory Commission in various dockets over the years.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my surrebuttal testimony is to first point out to the parties and the

Commission how close Tucson Electric Power Company's ("TEP") largest customer, Freeport's Sierrita mine ("Sierrita"), came to shutting down due to low commodity prices, which have still not fully recovered. This demonstrates the urgency for immediate action to reduce power costs that will assist Freeport in continuing to operate Sierrita and provide the enormous economic benefit to Pima County and the state of Arizona. In furtherance of this immediate need, I provide another market option for the Commission to consider in addition to the two joint buy-through proposals detailed in Mr. Kevin Higgins' Surrebuttal Testimony on behalf of Freeport, Arizonans for Electric Choice and Competition ("AECC") and Noble Americas Energy Solutions ("Noble Solutions").

As TEP's largest retail customer, Freeport's load at Sierrita – operating at only 75% of capacity – is still larger than the entire program size under AECC's original buy-through proposal, which is sized to be equivalent to the Arizona Public Service Company ("APS") AG-1 buy-through program. Therefore, even if this original buy-through proposal is approved, it might only provide partial access to alternative generation supply for Sierrita, and therefore limit the potential savings Sierrita needs to best reduce its costs.

Q. CAN YOU PLEASE COMMENT ON THE SETTLEMENT AGREEMENT THAT WAS FILED CONCERNING THE COMPANY'S REVENUE REQUIREMENT? DID FREEPORT SIGN THE SETTLEMENT AGREEMENT?

A. Yes, but not without much hesitation.

Q. PLEASE EXPLAIN.

A. While the Revenue Requirement Settlement Agreement ("Settlement") provides TEP an acceptable return, it does not address several important issues, such as providing Sierrita access to market-based generation that it needs to best manage one of its highest variable costs – electric power. Nonetheless, by resolving a number of revenue-related issues, the Settlement will allow the parties and the Commission to focus on this important issue, as well as cost allocation and a reduction of inter-class subsidies. These are issues that must be resolved if Sierrita is to have its best chance to continue being the economic resource it has been for Pima County and the state of Arizona the past several decades. The stakes are really high for Freeport and the communities it serves.

I. <u>FREEPORT'S SIERRITA MINING OPERATIONS AND ECONOMIC IMPACT ON LOCAL ECONOMY.</u>

A. <u>Background and Overview.</u>

Q. MR. MCELRATH, PLEASE PROVIDE A SUMMARY OF FREEPORT'S SIERRITA MINING OPERATIONS IN PIMA COUNTY.

A. Sierrita began operations in 1907 as an underground mine, which was converted to an open pit mine in 1957. In 2015, Freeport employed nearly 1,090 employees, which had a total impact of nearly 3,210 jobs on the Arizona economy. Operating at 75% capacity since January 2016, Sierrita currently employs 740 workers. In 2009, Freeport purchased the Twin Buttes copper mine which had ceased operations in 1994. This mine is adjacent to Sierrita, and can provide significant synergies in the Sierrita minerals district, including the potential for expanded mining activities.

Q. HAS AN INDEPENDENT STUDY BEEN CONDUCTED ON THE ECONOMIC IMPACT THAT FREEPORT'S SIERRITA MINING OPERATIONS HAVE HAD ON THE LOCAL ECONOMY AND THE STATE OF ARIZONA?

A. Yes. According to a study by the L. William Seidman Research Institute at Arizona State University ("ASU Study"), operations at Sierrita generated an estimated **$250.7** million in economic benefits for Pima County, and approximately **$343.6** million for the state of Arizona in 2015 alone. A chart depicting Sierrita's impacts on Pima County and Arizona in 2015 is attached hereto as Exhibit 1.

Q. DID THE STUDY PROVIDE THE AMOUNT OF BUSINESS TAXES FREEPORT PAYS TO PIMA COUNTY ANNUALLY?

A. Yes it does. Freeport paid nearly $14 million in business tax to Pima County in 2015.

Q. ARE THERE OTHER BENEFITS THAT SIERRITA PROVIDE TO RESIDENTS IN PIMA COUNTY BEYOND JOBS, VENDOR PURCHASES AND TAXES?

A. Most definitely. As a responsible corporate citizen, Freeport engages in and sponsors several community outreach programs and civic events. For instance, in 2010 Freeport established the Green Valley/Sahuarita Community Investment Fund, which awarded $577,000 in grants to various community nonprofit programs (i.e. local schools and food banks) in 2014, and another $555,000 in 2015.

B. Sierrita – Current Status of Operations.

Q. HOW CLOSE DID FREEPORT COME TO CLOSING ITS OPERATIONS AT SIERRITA?

A. Very close. Attached hereto as Exhibit 2 to my surrebuttal testimony are three press released made between October 2015 and April 2016. Initially, Freeport planned a 50% reduction in operating volume at Sierrita in response to low copper and molybdenum prices and planned a full curtailment of mining and milling operations once a water management system was developed. In January 2016, due to stabilized molybdenum market conditions and improved operating performance, Sierrita revised its planned production curtailment schedule to a 75% curtailment.

Q. IS MANAGEMENT AT TEP AWARE OF HOW CLOSE FREEPORT

CAME TO SHUTTING DOWN SIERRITA?

A. Yes, but it does not seem to concern TEP enough to make any meaningful buy-through proposal in this rate proceeding to afford Sierrita immediate relief from high rates. Freeport has tried working with TEP to find solutions that could reduce the likelihood of further reductions in operations at Sierrita, but to no avail. It appears that a Commission-mandated solution is our only option at this time.

Q. WHAT IS THE CURRENT STATUS OF SIERRITA?

A. Sierrita is operating at the reduced production rate of 75% of capacity. Freeport continues to carefully monitor operating results and market conditions and future production rate decisions at Sierrita will be based on these factors. Outside of labor costs, energy represents Sierrita's second largest variable operating expense.

Q. DOES ACCESS TO MARKET-BASED ALTERNATIVE GENERATION PLAY A ROLE FOR FREEPORT IN DETERMINING WHERE BEST TO INVEST THE COMPANY'S RESOURCES?

A. Yes. Freeport's Morenci mine expansion reached full production during Q2 of 2015, and Freeport's planned Lone Star development in Safford is progressing. Morenci and Safford are served by Morenci Water & Electric Company ("MW&E"), which is supplied primarily from the competitive generation wholesale market.

Q. TEP HAS PROPOSED AN ECONOMIC DEVELOPMENT RATE ("EDR") TO ENHANCE ECONOMIC DEVELOPMENT IN ITS SERVICE TERRITORY. WHAT KIND OF INCENTIVES WILL THE EDR PROVIDE FREEPORT IN DECIDING WHERE TO MAKE CONTINUED INVESTMENTS?

A. Absolutely none. An EDR may have some minimal success in attracting new or expanded operations for commercial and industrial customers, but Sierrita is neither new, nor are operations expanding. Further, EDR savings decline over a short number of years and default into the applicable retail tariff, while mining investments have a much longer horizon. Freeport prefers to have competitive choice in its generation supply as this is a far superior customer tool than an EDR.

Q. **DOES FREEPORT HAVE ANY PLANS TO FURTHER REDUCE ITS OPERATIONS AT SIERRITA?**

A. Freeport continues to carefully monitor operating results and market conditions and future production rate decisions will be based on these factors.

Q. **SO IF SIERRITA WERE TO COMPLETELY SHUT DOWN OPERATIONS, THE LIKELIHOOD IT WOULD BE RE-STARTED IS LOW?**

A. A restart would be dependent on favorable market and operating conditions that would justify the investment of re-establishing the workforce, replace lost equipment and all other expenses associated with bringing a mining operation back into production. I cannot stress enough the importance of providing Sierrita with the tools necessary to manage its energy costs, such as buy-through programs that allow for access to market generation.

Every penny counts, and Freeport's decisions concerning where to focus its investment dollars on a world-wide stage can turn on the slightest of margins.

II. <u>CHOICE AND MARKET BASED GENERATION</u>

A. <u>Background and overview</u>.

Q. **DOES FREEPORT SUPPORT THE IMPLEMENTATION OF CHOICE AND COMPETITION IN GENERATION SUPPLY HERE IN ARIZONA?**

A. Yes. Not only is access to competitive generation the stated public policy of the state of Arizona, but the Arizona Corporation Commission's own Five Year Strategic Plan for 2014-2019 calls "To promote the transition of the telecommunications and *electricity generation markets* from the *current regulated monopoly structure to one of competition* while ensuring safe and reliable service." [Emphasis added]. See Exhibit 3 attached hereto.

Q. HAS THE COMMISSION BEEN PROMOTING A TRANSITION TO COMPETITION IN ELECTRICITY GENERATION?

A. The Commission did approve a settlement agreement in APS' last rate case that included the AG-1 Tariff. However, the Commission has done nothing since to provide large customers access to competitive markets in electricity generation – even on a limited basis – outside of AG-1. In fact, it appears that Arizona is moving in the opposite direction.

Q. CAN YOU BE MORE SPECIFIC REGARDING YOUR CONTENTION THAT ARIZONA IS MOVING IN THE OPPOSITE DIRECTION?

A. Certainly. In Docket No. E-00000V-15-0094 [In the Matter of Resource Planning and Procurement in 2015 and 2016], the Commission is considering integrated resource plans ("IRP") submitted by TEP, APS and UNSE. Each of these regulated utilities' plans include load growth forecasts, and the need to acquire and/or construct new generation facilities to serve such growth on a long-term basis.

As a customer of TEP, Freeport will be expected to pay for the acquisition or construction of new generation facilities that the Commission considers "used and useful" as a result of a rate case, which is a very likely event when "acknowledged" by the Commission as a result of the IRP process. Freeport submitted written comments in the IRP docket arguing that allowing large, sophisticated users to "opt-out" and purchase electricity from the competitive market should be considered as an alternative to new generation. By ensuring that all resource alternatives are considered, including opt-out programs, the

Commission can evaluate those that may primarily benefit ratepayer impacts and/or economic growth, and not just the alternatives which primarily support a utility's profits. The IRP process should specifically consider the role that opt-out can play in mitigating the need for supply-side resources.

Additionally, increasing regulatory mandates in renewable generation ignores the role that competitive markets can play in promoting growth for the renewable industry. Instead of a mandate that further empowers incumbent utilities to add more costs for consumers, a move to a competitive generation market would allow all classes of customers to choose up to 100% of their generation from renewable energy. Competitive renewable providers could in turn build generation supply to meet this demand. For instance, in his Direct Testimony, Wal-Mart Stores, Inc.'s witness Chris Hendrix testifies that his company would like to purchase more renewables than the amount currently included in TEP's resource mix.[1]

Q. BUT HOW WOULD A COMPETITIVE GENERATION MARKET AFFECT TEP'S CURRENT GENERATION RESOURCES?

A. According to Mr. Hutchens, TEP will have future generation capacity needs of approximately 400MW beginning in 2018.[2] I am especially interested in his statement that continuing to rely on coal as a primary fuel source is just not a viable long-run strategy for TEP or its customers. Industrial customers like Freeport can complement TEP's long-term strategy to reduce its reliance on coal by an opt-out program, by removing generation load from the equation, thus allowing TEP to accelerate retirement of its coal units without a need to immediately replace them. While this may be an alternative for 2018, Sierrita requires a more immediate

[1] Direct Testimony on Rate Design and Cost of Service of Chris Hendrix, at p. 8.

[2] Rebuttal Testimony of David Hutchens at p. 9-10.

solution for cost savings.

Q. BUT ISN'T RELIANCE ON THE MARKET FOR GENERATION A RISKY PROPOSITION FOR LARGE CUSTOMERS?

A. Yes, just as the market can be a risky proposition for TEP. Freeport is a sophisticated user of electricity, with affiliates that include Commission jurisdictional electric utilities and an independent power marketer with FERC Exempt Wholesale Generator status and over 20 years of generation market contracting experience in South America, where competitive generation supply is the rule for industrial customers. The opportunity for Freeport to self-supply its Arizona operations at Sierrita can minimize the risk to TEP's other retail customers, and allow for the alignment of commodity risk profiles to meet Freeport's short and long-term objectives. By contrast, the current misalignment of risks between Freeport's inputs and outputs puts TEP's revenues and the communities Freeport operates in at risk due to further curtailment or closure. Furthermore, as a tariff customer, if Sierrita closes or curtails further – it will also be faced with a demand ratchet of 75% for eleven (11) months afterwards.

Q. DOES FREEPORT HAVE A SPECIFIC PROPOSAL FOR GIVING SIERRITA ACCESS TO THE COMPETITIVE GENERATION MARKET?

A. Yes. The solution Freeport is proposing at this time is modeled after the Franchise Agreement ("Agreement") among Phelps Dodge Safford, Inc. ("PD Safford"), MW&E and Graham County Electric Cooperative, Inc. ("Graham") regarding electric service to Freeport's mining operations in Safford, Arizona.

III. FRANCHISE AGREEMENT.

A. Overview of Proposal

Q. PLEASE SUMMARIZE THE BASIS OF FREEPORT'S PROPOSAL IN THIS PROCEEDING.

A. Freeport is proposing to utilize a model already approved by the Commission in 2006, which involved Freeport's PD Safford mine, MW&E and Graham County Electric Cooperative, Inc. ("Graham"). That arrangement involved the development of a mine at Safford, Arizona by PD Safford. This mine was located in Graham's service area and the parties entered into a Service Territory Franchise Agreement ("Agreement") which enabled MW&E to provide power to PD Safford for its mining operations. The Agreement was subsequently approved by the Commission on December 21, 2006.

Q. UNDER THE AGREEMENT, WHO PROVIDES OR ARRANGES FOR ALL ELECTRIC TRANSMISSION AND DISTRIBUTION LINES AND SUBSTATIONS FACILITIES REQUIRED IN CONNECTION WITH SERVING PD SAFFORD?

A. PD Safford made arrangements for all facilities to connect the PD Safford distribution system within the transmission system, including metering and communication facilities.

Q. DOES PD SAFFORD OWN, OPERATE AND MAINTAIN THE POWER DISTRIBUTION SYSTEM FACILITIES WITHIN THE PD SAFFORD AREA?

A. Yes.

Q. DID MW&E ARRANGE FOR AN INTERCONNECTION WITH THE ELECTRICAL TRANSMISSION FACILITIES OF SOUTHWEST TRANSMISSION COOPERATIVE?

A. Yes. Those interconnection facilities provided access to wholesale market supplies of power and energy to accommodate PD Safford. MW&E entered into service agreements for both firm and non-firm transmission services from Southwest Transmission.

Q. DID THE FRANCHISE AGREEMENT CONTAIN A TERM PERIOD?

A. Yes. It was for an initial period of ten years and could continue in effect for subsequent five (5) year extension periods beyond the initial period unless and until terminated by one of the parties providing at least one year and one day written notice in advance of the end of the initial franchise period or any subsequent period.

Q. IS THERE ANY FRANCHISE CHARGE TO BE PAID TO GRAHAM BY MW&E?

A. Yes.

Q. HAVE YOU ATTACHED A FORM THAT COULD BE USED AS A FRANCHISE AGREEMENT IN THIS PROCEEDING?

A. Yes. Exhibit 4 could be used as a possible format for a franchise agreement between MW&E and TEP as a result of this proceeding.

B. Benefits of a Franchise Agreement

Q. WOULD YOU EXPLAIN THE BENEFITS THAT WOULD RESULT FROM THE EXECUTION OF A SIMILAR FRANCHISE AGREEMENT INVOLVING TEP, MW&E AND FREEPORT?

A. Yes. I may be repeating some of my earlier comments with the following comments. However, I want to reemphasis the points.

First, the arrangement would enable Freeport to purchase power at a competitive market price, which today is much less than TEP's retail generation supply. As I have previously testified, energy is Freeport's second largest variable expense. Freeport sells its commodity products on the world market at market price. It does not set that sales price and can only impact that price by cutting production in low price periods or increasing production in high price periods. Freeport can only work to control its production costs.

Second, Freeport's ability to sell its product on the world market, at a price in excess of its production costs, enables it to be able to continue to operate the Sierrita Mine. However, I would like to again point out that Freeport operates a number of mines around the world an on a price per pound of copper produced basis, Sierrita's power costs are among the highest. Sierrita's ability to maintain operations is heavily dependent on its cost structure and energy is a significant component of their costs.

Third, by keeping the Sierrita Mine operating, Freeport will:

1. Continue to be able to employ employees from the Tucson area.
2. Continue to be able to purchase supplies from merchants in the Tucson area.
3. Continue to be able to employ services of companies in the Tucson area.
4. Continue to be able to pay taxes to the County and State.
5. Continue to be able to provide employees and funds in support of civic and charitable community activities in the Tucson area.

Fourth, by keeping costs as low as possible at Sierrita, the mine will still be contributing to TEP's fixed costs. Additionally, TEP would continue to provide electric service and receive revenue from Sierrita employees, as well as Tucson merchants who provide goods and/or services.

Q. **SO TO CLARIFY, THE FRANCHISE AGREEMENT OPTION YOU ARE SPONSORING TODAY IS IN ADDITION TO THE TWO BUY-THROUGH PROGRAM OPTIONS ADDRESSED IN MR. HIGGINS' SURREBUTTAL TESTIMONY?**

A. Yes, Freeport considers a franchise agreement between MW&E and TEP to be a third option for the Commission to consider. The two buy-through proposals addressed by Mr. Higgins can be important long-term tools for TEP's commercial and industrial customers to manage costs through market choice and competition. And while the third proposal I make herein provides the most practical relief for Sierrita, nothing does nor should preclude the Commission from taking both a short and long-term approach in transitioning towards a competitive market in generation, as evidenced by its own strategic plan.

Q: **DOES THIS CONCLUDE YOUR TESTIMONY?**

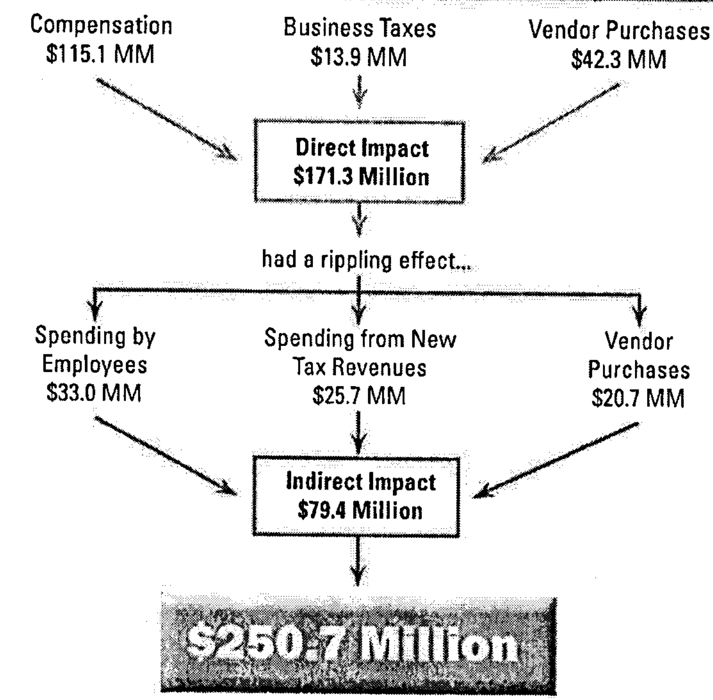
A: Yes.

EXHIBIT 1

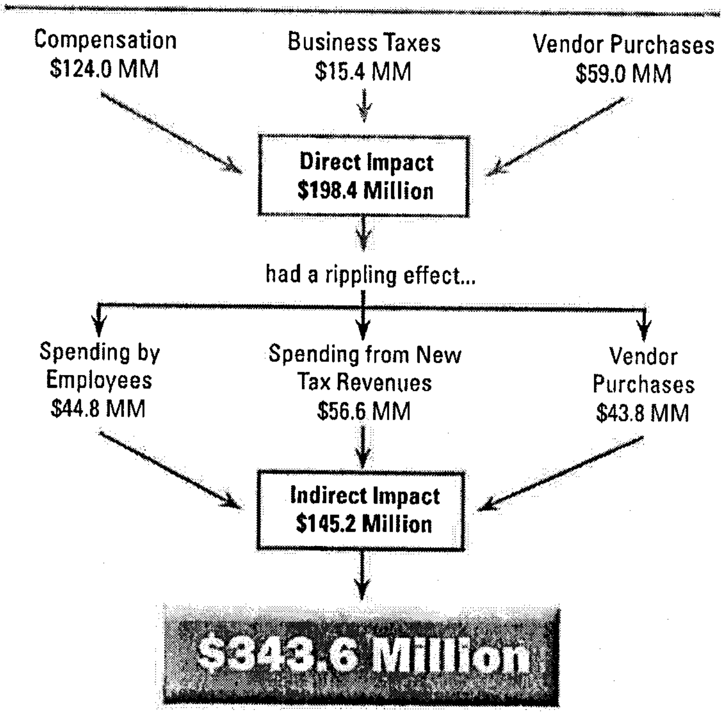
FREEPORT-McMoRAN

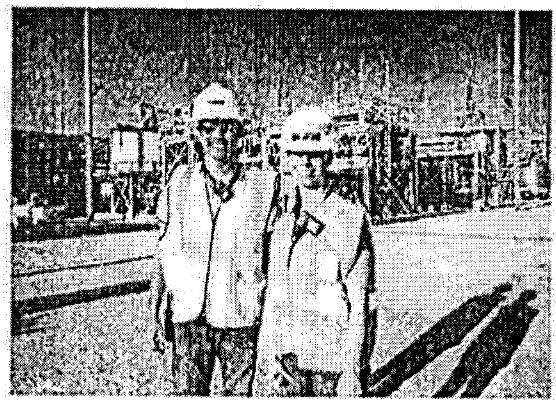
IMPACT OF SIERRITA OPERATIONS ON THE ECONOMY OF PIMA COUNTY AND ARIZONA — 2015

Sierrita Operations' Impact on Pima County



Sierrita Operations' Impact on Arizona





Freeport-McMoRan's Sierrita mine generated an estimated $250.7 million in economic benefits for Pima County and approximately $343.6 million for Arizona in 2015.

Freeport-McMoRan contributes in many ways to the sustainability of the various communities, counties and states in which we operate. They rely heavily on the economic benefits directly and indirectly provided by our various operations in the form of wages and taxes we pay as well as the goods and services we purchase. This direct spending ripples through the economy, inducing additional economic benefits and contributing to more jobs and greater tax revenues.

The charts to the left explain how Sierrita provides such a boost to the county and state economies.

Freeport-McMoRan's Sierrita mine had more than 1,090 employees at the end of 2015 and a total impact of nearly 3,210 jobs on Arizona's economy.

All economic impact numbers were produced by the L. William Seidman Research Institute, Arizona State University.

fcx.com

EXHIBIT 2

October 2015

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Freeport-McMoRan
Reports Third-Quarter and Nine-Month 2015 Results

- **Net loss** attributable to common stock totaled $3.8 billion, $3.58 per share, for third-quarter 2015. After adjusting for net charges totaling $3.7 billion, $3.43 per share, third-quarter 2015 adjusted net loss attributable to common stock totaled $156 million, $0.15 per share.
- **Consolidated sales** totaled 1.0 billion pounds of copper, 294 thousand ounces of gold, 23 million pounds of molybdenum and 13.8 million barrels of oil equivalents (MMBOE) for third-quarter 2015, compared with 1.1 billion pounds of copper, 525 thousand ounces of gold, 22 million pounds of molybdenum and 12.5 MMBOE for third-quarter 2014.
- **Consolidated sales** for the year 2015 are expected to approximate 4.1 billion pounds of copper, 1.2 million ounces of gold, 90 million pounds of molybdenum and 52.7 MMBOE, including 1.1 billion pounds of copper, 310 thousand ounces of gold, 21 million pounds of molybdenum and 13.3 MMBOE for fourth-quarter 2015.
- **Average realized prices** were $2.38 per pound for copper, $1,117 per ounce for gold and $55.88 per barrel for oil (including $11.03 per barrel for cash gains on derivative contracts) for third-quarter 2015.
- **Consolidated unit net cash costs** for third-quarter 2015 averaged $1.52 per pound of copper for mining operations and $18.85 per barrel of oil equivalents (BOE) for oil and gas operations.
- **Operating cash flows** totaled $822 million (including $507 million in working capital sources and changes in other tax payments) for third-quarter 2015. Based on current sales volume and cost estimates and assuming average prices of $2.40 per pound for copper, $1,150 per ounce for gold, $5.50 per pound for molybdenum and $50 per barrel for Brent crude oil for fourth-quarter 2015, operating cash flows are expected to approximate $3.3 billion for the year 2015. Using similar price assumptions, operating cash flows are expected to approximate $6.8 billion for the year 2016.
- **Capital expenditures** totaled $1.5 billion for third-quarter 2015, including $0.6 billion for major projects at mining operations and $0.7 billion for oil and gas operations. Capital expenditures are expected to approximate $6.3 billion for the year 2015, including $2.5 billion for major projects at mining operations and $2.8 billion for oil and gas operations. Capital expenditures are expected to approximate $4.0 billion for the year 2016.
- The **Cerro Verde expansion project** commenced operations in September 2015 and is expected to achieve full rates by early 2016.
- In third-quarter 2015, FCX announced **revised capital and operating plans** in response to market conditions. The revised plans include significant reductions in planned capital expenditures, production curtailments and cost reductions. FCX also announced today additional actions to further curtail copper and molybdenum production.
- FCX has sold 114.8 million shares of its common stock and generated gross proceeds of $1.2 billion under its **at-the-market equity programs**, including 97.5 million shares and gross proceeds of $1.0 billion during third-quarter 2015.
- At September 30, 2015, **consolidated debt** totaled $20.7 billion and **consolidated cash** totaled $338 million.
- In October 2015, FCX announced it is undertaking a **review of its oil and gas business** to evaluate strategic alternatives designed to enhance value to FCX shareholders and achieve self-funding of the oil and gas business from its cash flows and resources.
- In October 2015, the Indonesian government provided assurances to **PT Freeport Indonesia on its long-term mining rights.**

Third-quarter 2015 consolidated **molybdenum** sales of 23 million pounds approximated the July 2015 estimate and the third-quarter 2014 sales of 22 million pounds.

Third-quarter 2015 sales from oil and gas operations of 13.8 MMBOE, including 9.3 million barrels (MMBbls) of **crude oil**, 22.8 billion cubic feet (Bcf) of **natural gas** and 0.7 MMBbls of **natural gas liquids** (NGLs), approximated the July 2015 estimate of 13.6 MMBOE and were higher than third-quarter 2014 sales of 12.5 MMBOE, primarily reflecting higher volumes in the GOM, partly offset by lower volumes in California.

Consolidated sales for the year 2015 are expected to approximate 4.1 billion pounds of copper, 1.2 million ounces of gold, 90 million pounds of molybdenum and 52.7 MMBOE, including 1.1 billion pounds of copper, 310 thousand ounces of gold, 21 million pounds of molybdenum and 13.3 MMBOE for fourth-quarter 2015. Projected 2015 sales volumes are approximately 130 million pounds of copper and 90 thousand ounces of gold below the July 2015 estimates reflecting revised operating plans and ongoing El Niño weather conditions in Indonesia. With the completion of the Cerro Verde expansion project and access to higher grade ore at Grasberg in 2016, FCX expects sales volumes to approximate 5.2 billion pounds of copper for the year 2016.

Consolidated Unit Costs

Mining Unit Net Cash Costs. Consolidated average unit net cash costs (net of by-product credits) for FCX's copper mines of $1.52 per pound of copper in third-quarter 2015 were higher than unit net cash costs of $1.34 per pound in third-quarter 2014, primarily reflecting lower by-product credits, partly offset by lower site production and delivery costs mostly associated with higher volumes in North America.

Assuming average prices of $1,150 per ounce of gold and $5.50 per pound of molybdenum for fourth-quarter 2015 and achievement of current sales volume and cost estimates, consolidated unit net cash costs (net of by-product credits) for copper mines are expected to average $1.52 per pound of copper for the year 2015. Quarterly unit net cash costs vary with fluctuations in sales volumes and average realized prices (primarily gold and molybdenum prices). The impact of price changes for fourth-quarter 2015 on consolidated unit net cash costs would approximate $0.006 per pound for each $50 per ounce change in the average price of gold and $0.003 per pound for each $2 per pound change in the average price of molybdenum.

Unit net cash costs are expected to decline significantly in 2016, principally reflecting higher anticipated copper and gold volumes. Using the same metals price assumptions and assuming achievement of current sales volume and cost estimates, consolidated unit net cash costs (net of by-product credits) for copper mines are expected to average $1.15 per pound of copper for the year 2016.

Oil and Gas Cash Production Costs per BOE. Cash production costs for oil and gas operations of $18.85 per BOE in third-quarter 2015 were lower than cash production costs of $20.93 per BOE in third-quarter 2014, primarily reflecting lower production costs in California related to reductions in well workover expense and steam costs.

Based on current sales volume and cost estimates for fourth-quarter 2015, cash production costs are expected to approximate $19 per BOE for the year 2015.

MINING OPERATIONS

North America Copper Mines. FCX operates seven open-pit copper mines in North America - Morenci, Bagdad, Safford, Sierrita and Miami in Arizona, and Chino and Tyrone in New Mexico. All of the North America mining operations are wholly owned, except for Morenci. FCX records its 85 percent joint venture interest in Morenci using the proportionate consolidation method. In addition to copper, molybdenum concentrates and silver are also produced by certain of FCX's North America copper mines.

Operating and Development Activities. FCX has significant undeveloped reserves and resources in North America and a portfolio of potential long-term development projects. In the near term, FCX is deferring developing new projects as a result of current market conditions. Future investments will be undertaken based on the results of economic and technical feasibility studies, and market conditions.

The Morenci mill expansion project commenced operations in May 2014 and successfully achieved full rates in second-quarter 2015. The project expanded mill capacity from 50,000 metric tons of ore per day to approximately 115,000 metric tons of ore per day, which results in incremental annual production of approximately

225 million pounds of copper and an improvement in Morenci's cost structure. Morenci's copper production is expected to average 900 million pounds per year over the next five years.

FCX's revised plans for its North America copper mines incorporate reductions in mining rates to reduce operating and capital costs, including the suspension of mining operations at the Miami mine (which produced 33 million pounds of copper for the first nine months of 2015), a 50 percent reduction in mining rates at the Tyrone mine (which produced 65 million pounds of copper for the first nine months of 2015), a 50 percent reduction in operating rates at the Sierrita mine (which produced 140 million pounds of copper and 17 million pounds of molybdenum for the first nine months of 2015) as well as adjustments to mining rates at other North America mines. The revised plans at each of the operations incorporate the impacts of lower energy, acid and other consumables, reduced labor costs and a significant reduction in capital spending plans. These plans will continue to be reviewed and additional adjustments may be made as market conditions warrant.

Operating Data. Following is a summary of consolidated operating data for the North America copper mines for the third quarters and first nine months of 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Copper (millions of recoverable pounds)				
Production	499	423	1,420	1,203
Sales	483	436	1,441	1,230
Average realized price per pound	$ 2.42	$ 3.17	$ 2.59	$ 3.19
Molybdenum (millions of recoverable pounds)				
Production[a]	9	8	28	25
Unit net cash costs per pound of copper[b]				
Site production and delivery, excluding adjustments	$ 1.68	$ 1.83	$ 1.76	$ 1.86
By-product credits	(0.12)	(0.26)	(0.15)	(0.25)
Treatment charges	0.12	0.11	0.12	0.11
Unit net cash costs	$ 1.68	$ 1.68	$ 1.73	$ 1.72

a. *Refer to summary operating data on page 5 for FCX's consolidated molybdenum sales, which includes sales of molybdenum produced at the North America copper mines.*
b. *For a reconciliation of unit net cash costs per pound to production and delivery costs applicable to sales reported in FCX's consolidated financial statements, refer to the supplemental schedules, "Product Revenues and Production Costs," beginning on page XIV which are available on FCX's website, "fcx.com."*

North America's consolidated copper sales volumes of 483 million pounds in third-quarter 2015 were higher than third-quarter 2014 sales of 436 million pounds, primarily reflecting higher milling rates and ore grades at Morenci and Chino, and higher ore grades at Safford. North America copper sales are estimated to approximate 1.95 billion pounds for the year 2015, compared with 1.66 billion pounds in 2014.

Average unit net cash costs (net of by-product credits) for the North America copper mines were $1.68 per pound of copper in both the third quarters of 2015 and 2014, with favorable impacts from higher volumes offset by lower by-product credits. Average unit net cash costs (net of by-product credits) for the North America copper mines are expected to approximate $1.70 per pound of copper for the year 2015, based on current sales volume and cost estimates and assuming an average molybdenum price of $5.50 per pound for fourth-quarter 2015. North America's average unit net cash costs for fourth-quarter 2015 would change by approximately $0.004 per pound for each $2 per pound change in the average price of molybdenum.

January 2016

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Freeport-McMoRan Reports Fourth-Quarter and Year Ended December 31, 2015 Results

- **Net loss** attributable to common stock totaled $4.1 billion, $3.47 per share, for fourth-quarter 2015 and $12.2 billion, $11.31 per share, for the year 2015. After adjusting for net charges totaling $4.1 billion, $3.45 per share, for fourth-quarter 2015 and $12.1 billion, $11.23 per share, for the year 2015, adjusted net loss totaled $21 million, $0.02 per share, for fourth-quarter 2015 and $89 million, $0.08 per share, for the year 2015.
- **Consolidated sales** totaled 1.15 billion pounds of copper, 338 thousand ounces of gold, 20 million pounds of molybdenum and 13.2 million barrels of oil equivalents (MMBOE) for fourth-quarter 2015 and 4.07 billion pounds of copper, 1.25 million ounces of gold, 89 million pounds of molybdenum and 52.6 MMBOE for the year 2015.
- **Consolidated sales** for the year 2016 are expected to approximate 5.1 billion pounds of copper, 1.8 million ounces of gold, 73 million pounds of molybdenum and 57.6 MMBOE, including 1.1 billion pounds of copper, 200 thousand ounces of gold, 19 million pounds of molybdenum and 12.4 MMBOE for first-quarter 2016.
- **Average realized prices** were $2.18 per pound for copper, $1,067 per ounce for gold and $48.88 per barrel for oil (including $11.39 per barrel for cash gains on derivative contracts) for fourth-quarter 2015.
- **Consolidated unit net cash costs** averaged $1.45 per pound of copper for mining operations and $16.17 per barrel of oil equivalents (BOE) for oil and gas operations for fourth-quarter 2015. Consolidated unit net cash costs are expected to average $1.10 per pound of copper for mining operations and $15 per BOE for oil and gas operations for the year 2016.
- **Operating cash flows** totaled $612 million for fourth-quarter 2015 and $3.2 billion (including $0.4 billion in working capital sources and changes in other tax payments) for the year 2015. Based on current sales volume and cost estimates and assuming average prices of $2.00 per pound for copper, $1,100 per ounce for gold, $4.50 per pound for molybdenum and $34 per barrel for Brent crude oil, operating cash flows for the year 2016 are expected to approximate $3.4 billion (net of $0.6 billion in idle rig costs).
- **Capital expenditures** totaled $1.3 billion for fourth-quarter 2015 (including $0.6 billion for major projects at mining operations and $0.5 billion for oil and gas operations) and $6.35 billion for the year 2015 (including $2.4 billion for major projects at mining operations and $3.0 billion for oil and gas operations). Capital expenditures for the year 2016 are expected to approximate $3.4 billion, including $1.4 billion for major projects at mining operations and $1.5 billion for oil and gas operations, and excluding $0.6 billion in idle rig costs.
- In response to further weakening in market conditions in fourth-quarter 2015 and early 2016, FCX today **announced additional initiatives to accelerate its debt reduction plans** and is actively engaged in discussions with third parties regarding potential transactions. These initiatives follow a series of actions taken during 2015 to reduce costs and capital spending to strengthen FCX's financial position.
- Since August 2015, FCX has sold 210 million shares of its common stock and generated gross proceeds of approximately $2 billion under its **at-the-market equity programs.**
- At December 31, 2015, **consolidated debt** totaled $20.4 billion and **consolidated cash** totaled $224 million. At December 31, 2015, FCX had no amounts drawn under its $4.0 billion credit facility.

Fourth-quarter 2015 sales from oil and gas operations of 13.2 MMBOE, including 9.0 million barrels (MMBbls) of **crude oil**, 21.5 billion cubic feet (Bcf) of **natural gas** and 0.6 MMBbls of **natural gas liquids** (NGLs), approximated the October 2015 estimate and were higher than fourth-quarter 2014 sales of 12.1 MMBOE, primarily reflecting higher volumes in the GOM, partly offset by lower volumes in California.

Consolidated sales for the year 2016 are expected to approximate 5.1 billion pounds of copper, 1.8 million ounces of gold, 73 million pounds of molybdenum and 57.6 MMBOE, including 1.1 billion pounds of copper, 200 thousand ounces of gold, 19 million pounds of molybdenum and 12.4 MMBOE in first-quarter 2016. Anticipated higher grades from Grasberg in the second half of 2016 are expected to result in approximately 55 percent of consolidated copper sales and 75 percent of consolidated gold sales to occur in the second half of the year.

Consolidated Unit Costs

Mining Unit Net Cash Costs. Consolidated average unit net cash costs (net of by-product credits) for FCX's copper mines of $1.45 per pound of copper in fourth-quarter 2015 were lower than unit net cash costs of $1.47 per pound in fourth-quarter 2014, primarily reflecting lower site production and delivery costs mostly associated with higher sales volumes and the impacts of revised operating plans, partly offset by lower by-product credits.

Unit net cash costs for 2016 are expected to decline significantly from 2015, principally reflecting higher anticipated copper and gold volumes, the impact of lower energy and other input costs, and cost reduction initiatives. Assuming average prices of $1,100 per ounce of gold and $4.50 per pound of molybdenum for 2016 and achievement of current sales volume and cost estimates, consolidated unit net cash costs (net of by-product credits) for copper mines are expected to average $1.10 per pound of copper for the year 2016. Quarterly unit net cash costs vary with fluctuations in sales volumes and average realized prices (primarily gold and molybdenum prices). The impact of price changes on 2016 consolidated unit net cash costs would approximate $0.015 per pound for each $50 per ounce change in the average price of gold and $0.015 per pound for each $2 per pound change in the average price of molybdenum.

Oil and Gas Cash Production Costs per BOE. Cash production costs for oil and gas operations of $16.17 per BOE in fourth-quarter 2015 were lower than the cash production costs of $21.93 per BOE in fourth-quarter 2014, primarily reflecting higher volumes in Deepwater GOM, and lower maintenance and repair costs in both Deepwater GOM and California. Based on current sales volume and cost estimates, cash production costs are expected to approximate $15 per BOE for the year 2016. Lower cash production costs in 2016 primarily reflect increased production from the Deepwater GOM and cost reduction efforts.

MINING OPERATIONS

North America Copper Mines. FCX operates seven open-pit copper mines in North America - Morenci, Bagdad, Safford, Sierrita and Miami in Arizona, and Chino and Tyrone in New Mexico. All of the North America mining operations are wholly owned, except for Morenci. FCX records its 85 percent joint venture interest in Morenci using the proportionate consolidation method. In addition to copper, molybdenum concentrates and silver are also produced by certain of FCX's North America copper mines.

Operating and Development Activities. FCX has significant undeveloped reserves and resources in North America and a portfolio of potential long-term development projects. In the near term, FCX is deferring developing new projects as a result of current market conditions. Future investments will be undertaken based on the results of economic and technical feasibility studies and market conditions.

The Morenci mill expansion project, which commenced operations in May 2014, successfully achieved full rates in second-quarter 2015. The project expanded mill capacity from 50,000 metric tons of ore per day to approximately 115,000 metric tons of ore per day, which results in incremental annual production of approximately 225 million pounds of copper and an improvement in Morenci's cost structure. Morenci's copper production is expected to average approximately 900 million pounds per year over the next five years.

FCX's revised plans for its North America copper mines incorporate reductions in mining rates to reduce operating and capital costs, including the previously announced suspension of mining operations at the Miami mine (which produced 43 million pounds of copper for the year 2015), planned shutdown of the Sierrita mine (which produced 189 million pounds of copper and 21 million pounds of molybdenum for the year 2015), 50 percent reduction in mining rates at the Tyrone mine (which produced 84 million pounds of copper for the year 2015) and adjustments to mining rates at other North America mines. The revised plans at each of the operations incorporate

April 2016

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Freeport-McMoRan Reports First-Quarter 2016 Results

- **Net loss** attributable to common stock totaled $4.2 billion, $3.35 per share, for first-quarter 2016. After adjusting for net charges totaling $4.0 billion, $3.19 per share, first-quarter 2016 adjusted net loss attributable to common stock totaled $197 million, $0.16 per share.
- **Consolidated sales** totaled 1.1 billion pounds of copper, 201 thousand ounces of gold, 17 million pounds of molybdenum and 12.1 million barrels of oil equivalents (MMBOE) for first-quarter 2016, compared with 960 million pounds of copper, 263 thousand ounces of gold, 23 million pounds of molybdenum and 12.5 MMBOE for first-quarter 2015.
- The **Cerro Verde expansion project** reached full production capacity in first-quarter 2016, and Cerro Verde is on track to produce over 1 billion pounds of copper for the year 2016.
- **Consolidated sales** for the year 2016 (adjusted for the anticipated closing of the Morenci transaction in second-quarter 2016) are expected to approximate 5.0 billion pounds of copper, 1.85 million ounces of gold, 71 million pounds of molybdenum and 54.4 MMBOE, including 1.15 billion pounds of copper, 195 thousand ounces of gold, 19 million pounds of molybdenum and 13.5 MMBOE for second-quarter 2016.
- **Average realized prices** were $2.17 per pound for copper, $1,227 per ounce for gold and $29.06 per barrel for oil for first-quarter 2016.
- **Consolidated unit net cash costs** averaged $1.38 per pound of copper for mining operations and $15.85 per barrel of oil equivalents (BOE) for oil and gas operations for first-quarter 2016. Consolidated unit net cash costs for the year 2016 are expected to average $1.05 per pound of copper for mining operations and $15 per BOE for oil and gas operations.
- **Operating cash flows** totaled $740 million (including $188 million in working capital sources and changes in other tax payments) for first-quarter 2016. Based on current sales volume and cost estimates and assuming average prices of $2.25 per pound for copper, $1,250 per ounce for gold, $5 per pound for molybdenum and $45 per barrel for Brent crude oil for the remainder of 2016, operating cash flows for the year 2016 are expected to approximate $4.8 billion (including $0.8 billion in working capital sources and changes in other tax payments).
- **Capital expenditures** totaled $982 million for first-quarter 2016, consisting of $459 million for mining operations (including $350 million for major projects) and $523 million for oil and gas operations. Capital expenditures are expected to approximate $3.3 billion for the year 2016, consisting of $1.8 billion for mining operations (including $1.4 billion for major projects) and $1.5 billion for oil and gas operations.
- At March 31, 2016, **consolidated debt** totaled $20.8 billion and **consolidated cash** totaled $331 million. At March 31, 2016, FCX had $3.0 billion available under its $3.5 billion credit facility.
- During first-quarter 2016, FCX entered into agreements to **sell an additional 13 percent ownership in Morenci** and to **sell an interest in the Timok exploration project in Serbia** for aggregate consideration of $1.3 billion. In addition, in April 2016, FCX entered into an agreement to **sell certain oil and gas royalty interests** for $0.1 billion. These transactions are expected to close in second-quarter 2016.
- FCX continues to **advance discussions for the sale of certain interests in its mining and oil and gas assets** to accelerate its debt reduction initiatives. FCX expects to achieve additional progress during second-quarter 2016.

Consolidated sales for the year 2016 are expected to approximate 5.0 billion pounds of copper, 1.85 million ounces of gold, 71 million pounds of molybdenum and 54.4 MMBOE, including 1.15 billion pounds of copper, 195 thousand ounces of gold, 19 million pounds of molybdenum and 13.5 MMBOE for second-quarter 2016. Projected consolidated copper sales have been adjusted for the anticipated closing of the Morenci transaction in second-quarter 2016. Anticipated higher grades from Grasberg in the second half of 2016 are expected to result in approximately 55 percent of consolidated copper sales and 80 percent of consolidated gold sales to occur in the second half of the year.

Consolidated Unit Costs

Mining Unit Net Cash Costs. Consolidated average unit net cash costs (net of by-product credits) for FCX's copper mines of $1.38 per pound of copper in first-quarter 2016 were lower than unit net cash costs of $1.64 per pound in first-quarter 2015, primarily reflecting higher copper sales volumes in South America and the impact of ongoing cost reduction initiatives.

Assuming average prices of $1,250 per ounce of gold and $5 per pound of molybdenum for the remainder of 2016 and achievement of current sales volume and cost estimates, consolidated unit net cash costs (net of by-product credits) for copper mines are expected to average $1.05 per pound of copper for the year 2016. The impact of price changes for the remainder of 2016 on consolidated unit net cash costs would approximate $0.015 per pound for each $50 per ounce change in the average price of gold and $0.01 per pound for each $2 per pound change in the average price of molybdenum. Quarterly unit net cash costs vary with fluctuations in sales volumes and realized prices primarily for gold and molybdenum.

Oil and Gas Cash Production Costs per BOE. Cash production costs for oil and gas operations of $15.85 per BOE in first-quarter 2016 were lower than cash production costs of $20.26 per BOE in first-quarter 2015, primarily reflecting increased production from the Deepwater Gulf of Mexico (GOM) and ongoing cost reduction efforts.

Based on current sales volume and cost estimates, cash production costs are expected to approximate $15 per BOE for the year 2016.

MINING OPERATIONS

North America Copper Mines. FCX operates seven open-pit copper mines in North America - Morenci, Bagdad, Safford, Sierrita and Miami in Arizona, and Chino and Tyrone in New Mexico. In addition to copper, molybdenum concentrate and silver are also produced by certain of FCX's North America copper mines.

All of the North America mining operations are wholly owned, except for Morenci. FCX records its 85 percent joint venture interest in Morenci using the proportionate consolidation method. In February 2016, FCX entered into a definitive agreement to sell an additional 13 percent joint venture interest in Morenci, which is expected to close in second-quarter 2016.

Operating and Development Activities. FCX has significant undeveloped reserves and resources in North America and a portfolio of long-term development projects. In the near term, FCX is deferring development of new projects as a result of current market conditions. Future investments will be undertaken based on the results of economic and technical feasibility studies, and market conditions.

During 2015, FCX's revised plans for its North America copper mines to incorporate reductions in mining rates to reduce operating and capital costs, including the suspension of mining operations at the Miami mine, a transitioned suspension of production at the Sierrita mine, a 50 percent reduction in mining rates at the Tyrone mine and adjustments to mining rates at other North America mines. The revised plans at each of the operations incorporate the impacts of lower energy, acid and other consumables, reduced labor costs and a significant reduction in capital spending plans. These plans continue to be reviewed and additional adjustments will be made as market conditions warrant.

EXHIBIT 3

ARIZONA CORPORATION COMMISSION

Strategic Plan 2014—2019

Five Year Strategic Plan

FY2013 – FY2018

MISSION STATEMENT

- Exercise exclusive state regulatory authority over public service corporations public utilities) in the public interest;
- Grant corporate status and maintain public records;
- Ensure the integrity of the securities marketplace; and
- Foster the safe operation of railroads and gas pipelines in Arizona.

ARIZONA CORPORATION COMMISSION

Strategic Plan 2014—2019

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Goals (cont.)

Information Technology

1. To provide electronic interaction effectively with the public and other governmental entities. In addition, to implement effective protocols, software, and communication with the public to allow them to retrieve and submit data, forms, and all other documents.
2. To use information technologies effectively to enhance intra-agency Communications.
3. To improve employees' preparation to use technology and react to their job-specific needs.

Legal

1. To provide efficient, high-quality legal representation.
2. To provide high-quality representation in administrative matters before the Corporation Commission
3. To provide high-quality representation in Judicial matters before various courts.
4. To provide high-quality legal advice to the Commission.

Safety

Railroad

1. To promote and ensure the safe operation of Arizona railroads.
2. To ensure rail/highway grade crossings safety.

Pipeline

1. To protect the public and the environment by providing the highest level of pipeline safety awareness
2. To ensure the pipeline operators in Arizona operate gas pipeline systems as safely as possible.
3. To receive and maintain an interagency agreement with the Federal Dept. of Transportation to ensure safe operations of interstate pipeline.
4. To maintain and improve the professional skills of the ACC pipeline staff.

Securities

1. To ensure that registered securities offered to public investors are structured fairly and equitably and fully disclose all information necessary for an investor to make an informed decision.
2. To reduce the public investor losses and protect Arizona's reputation from damage caused by fraudulent sales and services peddled to victims by unlicensed and unregistered frauds.
3. Continue to monitor the integrity of the investment marketplace to allow for enhanced capitol formation while deterring and adjudicating fraudulent practices.

Utilities

1. To ensure that utility service within the Commission's jurisdiction is available to all consumers at authorized rates.
2. To promote the transition of the telecommunications and electricity generation markets from the current regulated monopoly structure to one of competition while ensuring safe and reliable service.
3. To maximize the Division's operating efficiency through modernization of electronic processing and enhancing the Division's information technology.
4. To maintain public involvement, accessibility, and regulatory oversight by conducting workshops, forums, and community outreach programs.

EXHIBIT 4

SERVICE TERRITORY FRANCHISE AGREEMENT

AMONG

FREEPORT-McMoRan SIERRITA INC.

THE MORENCI WATER AND ELECTRIC COMPANY

AND

TUCSON ELECTRIC POWER COMPANY

SERVICE TERRITORY FRANCHISE AGREEMENT

This SERVICE TERRITORY FRANCHISE AGREEMENT (Franchise Agreement) is entered into this _____ day of _____________, 2016, by and among Freeport-McMoRan Sierrita Inc. (Sierrita), The Morenci Water and Electric Company (MW&E) and Tucson Electric Power Company (TEP). Sierrita is a Delaware corporation which is a wholly-owned subsidiary of the Freeport Minerals Corporation and which is authorized and licensed to do business in the State of Arizona. MW&E is a wholly-owned subsidiary of Freeport Minerals Corporation, organized and existing under the laws of the State of Arizona. TEP is a wholly-owned subsidiary of Fortis Inc. organized and existing under the laws of the State of Arizona. Sierrita, MW&E and TEP are referred to collectively herein as the "Parties".

WHEREAS, MW&E has been granted a certificate of convenience and necessity (CC&N) to provide utility services in the vicinity of Morenci, Arizona in Greenlee County;

WHEREAS, Sierrita has an active mining and milling operation on lands owned or controlled by it in the area west of the community of Green Valley, Arizona ("Sierrita Mine");

WHEREAS, TEP has been granted a CC&N to construct electric transmission and distribution facilities and deliver electricity within certain portions of Pima County, including the site of the Sierrita Mine (TEP Service Territory);

WHEREAS, TEP has existing 138kV electric transmission service to the existing Sierrita Mine and Sierrita owns a 138kV substation to deliver energy required to serve the Sierrita Mine;

WHEREAS, Sierrita prefers that the electric power and energy to be consumed within the Sierrita Mine be provided by or through MW&E; and

WHEREAS, TEP is willing to provide a franchise right to MW&E (i) to use existing TEP facilities necessary to supply energy and (ii) to supply energy to be consumed only within certain boundaries of the Sierrita Mine (such boundaries are precisely identified on Exhibit A hereto and are referred to herein as the "Freeport-McMoRan Sierrita Area") in exchange for the consideration set forth in this Franchise Agreement;

NOW, THEREFORE, in consideration of the premises set forth above and for other good and valuable consideration, the receipt and sufficiency of which the Parties hereby acknowledge, the Parties mutually agree as follows:

Section 1. Effective Date.

This Franchise Agreement shall be effective upon its execution by the Parties (Effective Date), subject to the receipt of a final, non-appealable order of the Arizona Corporation Commission (ACC) specifying its approval. TEP shall promptly submit this Franchise Agreement to the ACC for its approval. Sierrita and MW&E shall provide all necessary assistance to TEP in seeking ACC approval. Should the ACC reject the Franchise Agreement or require as a condition of approval of the Franchise Agreement any material changes or material modifications that are unacceptable to any Party, the Parties shall negotiate in good faith to attempt to modify, within 60 days of receipt of notice of such rejection or unacceptable requirement(s), this Franchise Agreement so as to attempt to secure the approval of the ACC.

Section 2. Termination.

After the Effective Date, this Franchise Agreement shall remain in effect for a period of ten (10) years and shall continue in effect for subsequent five (5) year extension periods beyond the Initial Franchise Period, unless and until terminated by a Party, as follows:

This Franchise Agreement may be terminated by Sierrita and MW&E or by TEP as of the end of the calendar year of the Initial Franchise Period or at the end of any subsequent five (5) year extension period that has occurred after the end of the Initial Franchise Period (Subsequent Period).

To exercise its right to terminate this Franchise Agreement, Sierrita and MW&E or TEP shall provide written notice to the other(s) at least one year and one day in advance of the end of the Initial Franchise Period or any Subsequent Period.

Upon termination of this Franchise Agreement, all rights of MW&E to construct, operate and maintain electric facilities and provide power and energy within the Freeport-McMoRan Sierrita Area shall cease. MW&E shall not be required to relinquish ownership of any facilities that have been constructed for the purpose of serving the Sierrita MW&E Loads.

Section 3. Franchise Agreement.

For the term of this Franchise Agreement and with respect to the Freeport-McMoRan Sierrita Area, excluding the loads existing within the Freeport-McMoRan Sierrita Area that are currently served from TEP's two (2) distribution circuits located within the Freeport-McMoRan Sierrita Area and any expansions of such loads, TEP grants to MW&E the rights to:

3.1 Firm transmission capacity on the existing TEP electric transmission facilities required to serve the Sierrita MW&E Loads;

3.2 Construct, own, operate and maintain a transmission line or lines connecting the Sierrita MW&E Loads with other transmission system(s); and

3.3 Secure power and energy for delivery over the facilities referred to in Sections 3.1 and 3.2, which shall comprise the Sierrita Electric System, to which all Sierrita MW&E Loads shall be connected.

Such rights on the terms granted by this Agreement shall extend only to the boundaries of the Freeport-McMoRan Sierrita Area and neither Sierrita nor MW&E shall by any action including, but not limited to, the filing of an application with the ACC seek to extend or modify the boundaries of the Freeport-McMoRan Sierrita Area or the terms of this Agreement. Sierrita and MW&E expressly acknowledge that (i) a material inducement and consideration for TEP to enter into this Franchise Agreement is its right and ability to continue to serve loads outside the Freeport-McMoRan Sierrita Area and; (ii) any breach of this condition would cause immediate, irreparable harm not compensable solely by monetary damages which may be redressed by equitable relief. Nothing herein, however, shall restrict MW&E's ability to extend its CC&N in areas which are outside of the TEP Service Territory.

Section 4. Services to be Provided.

4.1 For the Freeport-McMoRan Sierrita Area, MW&E shall provide the following:

4.1.1 All arrangements for the metering and communications equipment required to monitor and bill for the Franchise Charge associated with the demand and energy passing through the TEP 138kV Delivery Point to the Sierrita 138kV substation, which TEP metering and communications equipment already exist; and

4.1.2 All arrangements needed to deliver power and energy over transmission systems from the source of such power and energy for the Sierrita MW&E Loads.

4.2 For the Freeport-McMoRan Sierrita Area, TEP shall provide the following:

4.2.1 Firm transmission capacity across the TEP system for the delivery of power and energy for the the Sierrita Mine.

Section 5. Franchise Charge.

So long as this Franchise Agreement is in effect, TEP shall bill to MW&E and MW&E shall pay TEP monthly in accordance with Section 6 a monthly franchise charge determined as follows (Franchise Charge):

5.1 In the Initial Franchise Period, the Franchise Charge shall be the applicable of

The Franchise Charge shall be an amount determined as the product of the Franchise Fee of ____(TBD)____ multiplied by the demand/energy of the Sierrita MW&E Load as metered at the TEP 138kV Delivery Point.

Section 6. Billing and Payment.

Each billing period shall be one (1) calendar month (Billing Month). For each Billing Month, the following shall apply:

6.1 Based upon metered data, pursuant to Section 4. I .2, supplied byTEP, TEP shall bill MW&E with a copy to Sierrita on or before the fifteenth (15th) day of the month following the Billing Month for the Franchise Charge. MWE shall have the right to observe monthly meter reads and/or to request and receive data verifying the amount of demand and energy metered at the TEP 138kV Delivery Point. The meter(s) maintained at the TEP 138kV Delivery Point shall be tested for accuracy at TEP's expense at least annually and MWE shall have the right to attend such meter tests.

6.2 MW&E shall pay TEP the total of the monthly charge by the later of the 20th day of the month or ten (10) days after receipt of the bill. Failing timely payment of the monthly charge by MW&E, Sierrita shall be obligated to pay TEP on the terms specified herein.

6.3 MW&E shall electronically wire transfer funds to a bank of TEP's choice or transmit funds by any other method which provides collected funds on or before payment due date. Amounts not paid by the due date shall be payable by Sierrita or MW&E with interest accrued on each calendar day from the due date to the date of payment. Interest shall accrue at a rate of: (i) the then-effective prime commercial lending rate per annum published in the Money Rates section of The Wall Street Journal, or (ii) in the event the interest rate provided for herein should at any time exceed the maximum rate that may be so legally charged, the maximum rate that may be legally charged by TEP. Should The Wall Street Journal discontinue publication of the prime commercial lending rate, the Parties shall endeavor to agree on an acceptable substitute.

6.4 In the event any portion of any bill is disputed by MW&E, the disputed amount shall be paid, under protest, when due. If the protested portion of the payment is found to be incorrect, TEP shall promptly cause to be refunded to the paying party, either Sierrita or MW&E, any amount due, including interest accrued on each calendar day from the date of payment to the date the refund check is mailed by TEP. The same interest rate and computation method shall be applied to the determination of interest due herein as provided in Section 6.3.

6.5 In the event, as a result of a meter test or otherwise, a Party determines that any metered data is incorrect beyond a limit of one percent (1%) fast or slow, the Franchise Charges for the previous six (6) months, but not to exceed such six (6) month period, shall be presumed to be incorrect as billed and paid (unless demonstrated to the contrary). In such event, TEP and MW&E shall estimate the correction necessary for such metered data to be no more than one percent (1%) inaccurate and additional payment shall be made or amounts refunded, as appropriate, to adjust for such incorrect metered data for such six (6) month period, without interest.

6.6 No payment made to or received by TEP pursuant to this Section 6 shall constitute a waiver of any right of Sierrita, MW&E or TEP to contest the correctness of any monthly charge by TEP or metered data supplied by TEP; provided, however, that any bill rendered by TEP shall become final and non-contestable if protest is not received or made by TEP within six (6) months of the bill date.

6.7 TEP shall mail or send by telephone facsimile transmission or other electronic means any bills and refunds to Sierrita's or MW&E's billing address as designated from time to time in writing by Sierrita or MW&E.

Section 7. Notices.

Except only as herein otherwise expressly provided, any notice, demand or request provided for in this Franchise Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given or made if delivered in person or by any other qualified and recognized delivery service, or sent by United States mail postage prepaid to the persons specified below:

To: Freeport-McMoRan Sierrita Inc.
Director Energy Services
333 North Central Avenue
Phoenix, Arizona 85004

To: The Morenci Water & Electric Company
President
P.O. Box 68
Morenci, Arizona 85540

To: Tucson Electric Power Company
P. O. Box 77
Tucson, Arizona 85702

Any Party may at any time, by written notice to the other Party, change the designation or address of the person so specified as the one to receive notices pursuant to this Franchise Agreement.

Section 8. Entire Agreement.

The complete agreement of the Parties is set forth in this Franchise Agreement and all prior communications, whether written or oral, are hereby abrogated and withdrawn.

Section 9. Amendments.

This Franchise Agreement may be amended by, and only by, a written instrument duly executed by each Party.

Section 10. Waivers.

The waiver by any Party of any breach of any term, covenant or condition contained herein shall not be deemed a waiver of any other term, covenant or condition or any subsequent breach of the same or any other term, covenant or condition contained herein.

Section 11. Regulatory Authority and Governmental Authority.

The effectiveness of this Franchise Agreement is subject to its approval by the ACC. Once so approved, the Parties intend that the rates, charges, terms and conditions of service under this Franchise Agreement shall remain in effect unless changed by the mutual agreement of the Parties.

Section 12. Information Exchange.

The Parties shall cooperate in the exchange of information between themselves in order to further the purposes of this Franchise Agreement and to verify compliance with the terms of this Franchise Agreement.

Section 13. Representations and Warranties.

13.1 TEP represents, warrants and covenants to Sierrita and MW&E as follows:

13.1.1 TEP is an electric utility duly organized, validly existing and in good standing under the laws of the State of Arizona and has corporate power and authority to execute and deliver this Franchise Agreement and perform each obligation hereunder, and to carry on its business as such business is now being conducted and as it is contemplated hereunder that it will be conducted during the term hereof.

13.1.2 The execution, delivery and performance of this Franchise Agreement by TEP has been duly and effectively authorized by all requisite corporate action.

13.2 Freeport-McMoRan Sierrita Inc. represents, warrants and covenants to TEP as follows:

13.2.1 Sierrita is a corporation duly organized and validly existing and in good standing under the laws of the State of Delaware and authorized to do business in the State of Arizona and has the power and authority to execute and deliver this Franchise Agreement and to perform its obligations hereunder, and to carry on its business as it is now being conducted and as it is contemplated hereunder to be conducted during the term hereof.

13.2.2 The execution, delivery and performance of this Franchise Agreement by Freeport-McMoRan Sierrita Inc. has been duly and effectively authorized by all requisite corporate action.

13.3 MW&E represents, warrants and covenants to TEP as follows:

13.3.1 MW&E is a corporation duly organized and validly existing and in good standing under the laws of the State of Arizona and has the power and authority to execute and deliver this Franchise Agreement and to perform its obligations hereunder, and to carry on its business as it is now being conducted and as it is contemplated hereunder to be conducted during the term hereof.

13.3.2 The execution, delivery and performance of this Franchise Agreement by MW&E has been duly and effectively authorized by all requisite corporate action.

Section 14. Successors and Assigns.

No Party shall assign its interest in the Franchise Agreement in whole or part without the prior written consent of the other Party. Such consent shall not be unreasonably withheld.

Section 15. Governing Law.

This Franchise Agreement shall be governed and construed in accordance with the laws of the State of Arizona, without giving effect to its conflict of law principles. Jurisdiction shall be in Arizona state courts and venue shall be in the County of Pima.

Section 16. Miscellaneous.

16.1 Counterparts. This Franchise Agreement may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Franchise Agreement by signing any such counterpart.

16.2 Binding Effect. This Franchise Agreement shall be binding upon the Parties, and their respective successors and assigns.

16.3 Signatures. The signatories hereto represent that they have been appropriately authorized to enter into this Franchise Agreement on behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the undersigned have duly executed this Franchise Agreement as of the date first set forth herein.

TUCSON ELECTRIC POWER COMPANY

By:________________________________

Its:________________________________

ATTEST:__________________________

Dated:_____________________________

FREEPORT-MCMORAN SIERRITA, INC.

By:________________________________

Its:________________________________

ATTEST:__________________________

Dated:_____________________________

THE MORENCI WATER & ELECTRIC COMPANY

By:________________________________

Its:________________________________

ATTEST:__________________________

Dated:_____________________________

EXHIBIT A

FREEPORT-McMoRAN SIERRITA AREA

RECEIVED
JAN 17 1990
UTILITIES DIVISION

SERVICE DATE
JAN 17 1990

EXHIBIT
RUCO-1
ADMITTED

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PUGET SOUND POWER & LIGHT COMPANY, Respondent.	DOCKET NO. U-89-2688-T
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PUGET SOUND POWER & LIGHT COMPANY, Respondent.	DOCKET NO. U-89-2955-T THIRD SUPPLEMENTAL ORDER

PROCEEDING: On February 17, 1989, Puget Sound Power & Light Company, hereafter referred to as "respondent", "company", or "Puget", filed tariff revisions designed to produce a general increase in its rates and charges for electric service in the state of Washington in the approximate amount of $70.5 million. The company calculated this number by adding average 1989 ECAC revenues to the level of rates approved in the last general rate case and calling the result "present rates". The tariff filings were suspended by Commission order issued March 8, 1989, under Docket No. U-89-2688-T.

On May 26, 1989, Puget filed a revision to its Tariff WN U-60. The tariff revisions would move into general rates approximately $75 million in rates which had been included in the company's Energy Cost Adjustment Clause (ECAC) proceeding. This treatment was described in Docket No. U-89-2688-T, but not included in the tariff sheet revisions filed with that case. These tariff revisions were suspended by Commission order dated June 7, 1989, under Docket No. U-89-2955-T.

The two dockets were consolidated by Commission order dated September 8, 1989.

TABLE IX

Puget Sound Power & Light Company
Calculation of Revenue Requirement

Line No.			Commission
1	Rate Base		$1,846,664,716
2	Rate of Return		10.22%
3	Line 1 Times Line 2		$188,729,134
4	Conservation Investment	$97,365,090	
5	Return on Conservation	0.0083	808,130
6	Net Operating Income Requirement		$189,537,264
7	Net Operating Income Adjusted		123,811,142
8	Net Operating Income Deficiency		$65,726,123
9	Conversion Factor		0.6302472
10	Revenue Requirement Deficiency		$104,286,259
11	Rev. Req. Ass. to W/S Customers		124,636
12	Required Tariff Increase		$104,161,623
13	ECAC Offset		74,598,263
14	Net Rev. Req. (10 - 13)		29,687,996

XI. COST-OF-SERVICE STUDIES

A. History

Once the Commission has determined a utility's revenue requirement, this revenue requirement must be allocated among the various customer classes. The Commission is Cause No. U-78-05 directed that future rate filings be accompanied by embedded cost-of-service studies to assist in making rate design decisions consistent with the standards of the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Commission has considered over the years since Cause No. U-78-05 a variety of cost-of-service studies submitted by the three investor-owned electric utilities. The Commission in Cause No. U-78-05 considered and rejected the principles of marginal cost for use in developing rate structures. The Commission concluded in that cause that studies based on embedded costs would be most consistent with other ratemaking determinations. The Commission noted later in its Second Supplemental Order in Cause Nos. U-82-10/11 that embedded cost-of-service studies could be forward-looking by use of historical cost for functionalizing to production and other categories, followed by a classification method which would recognize the current cost relationships between baseload and peak facilities.

Embedded cost-of-service studies analyze the revenue requirements of various customer load classes on the basis of cost incurrence. After direct assignment of any costs which are directly assignable to a particular class, the remaining costs are assigned using three basic steps. First, costs are identified by function as related to production, transmission, distribution, or customer service. Second, the costs within each function are classified as related to demand, energy, or customer service. Third, costs which have been classified to the three cost components are allocated to customer classes of service.

B. Presentations of the Parties

David W. Hoff presented the company's cost-of-service study in Exhibit 530. The study showed the following current positions of the customer classes, relative to parity: residential .93; secondary general service 1.21; primary general service 1.03; high voltage .88; outdoor lighting 1.10; and firm wholesale for resale 1.01. The company did not propose spreading rates solely on cost-of-service study results.

The Commission staff did not present a cost-of-service study. Commission staff witness Bruce Folsom testified he did not take a position regarding the company's cost-of-service study [TR 2202]. The Commission staff indicated on brief it was accepting as fair the company's model results for purposes of this proceeding. Commission staff further recommended methodologies other than this be examined in future proceedings.

Public Counsel witness Jim Lazar did two cost-of-service studies. He recommended adoption of his "Public 2" study which he described as combining Commission-approved methods and allocation of costs for peaking resources based on the 200-hour point on the load duration curve. Mr. Lazar recommended rejection of the company's study because of problems with peak allocation, fuel costs, and distribution costs. The results of Mr. Lazar's preferred study showed high voltage, resale, and primary general service customer classes are underpaying, and the secondary general service, lighting, and residential customer classes are overpaying, in comparison to their costs incurred. Public Counsel on brief requested the Commission include in its order specific directives regarding methods to be used in future cost-of-service studies.

Intervenor WICFUR presented a cost-of-service study through George Carter. Mr. Carter made several revisions to the company's study, particularly regarding the classification of non-generation-related transmission and the company's peak credit classifier. Mr. Carter's study found that high-voltage customers are contributing a rate of return approximately equal to the average system rate of return.

C. Commission Analysis of Cost-of-Service Studies

As discussed by the Commission in the past, there are many valid methodologies for performing cost-of-service studies. Each methodology has strengths and weaknesses. The Commission in the years since Cause No. U-78-05 has been presented with a variety of cost-of-service variations. Often the Commission has instructed companies to present studies which contain alternative methodologies for the Commission's evaluation and comparison.

Inherent in this approach has been the philosophy that a variety of methodologies may be appropriate, depending on the circumstances of a company and its ratepayers. It is conceivable that different parties might employ equally valid methodologies which would bring about different results.

The Commission in making its rate spread decisions has considered each party's cost-of-service study. The Commission will continue to maintain the view that less emphasis should be placed on arguments regarding the elements of each cost-of-service study and more emphasis placed on the application of the study results.

In this case, the only directive the Commission will give regarding future cost-of-service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum-sized system is not. The parties should not use the minimum system approach in future studies.

EXHIBIT
RUCO 2
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322 et al.

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 3, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of Tucson Electric Power Company's ("TEP" or "Company") application for a permanent rate increase, filed with the Arizona Corporation Commission ("ACC" or "Commission") on November 5, 2015, RUCO recommends the following:

Cost of Equity – RUCO recommends that the Commission adopt a 9.20 percent cost of common equity. RUCO's 9.20 percent is the result obtained from the Discounted Cash Flow model ("DCF"), Capital Asset Pricing Model ("CAPM") and a Comparable Earnings Analysis used in RUCO's cost of equity analysis, and is 115 basis points lower than TEP's proposed 10.35 percent cost of common equity.

Cost of Debt – RUCO recommends that the Commission adopt the actual cost of long-term debt of 4.32 percent which is TEP's proposed end of test year cost of long-term debt. This compares to the cost of long-term debt previously approved in Decision No. 73912 of 5.18 percent.

Capital Structure – RUCO recommends that the Commission adopt TEP's actual end of test year capital structure comprised of no short-term debt, 49.97 percent long-term debt and 50.03 percent common equity.

Original Cost Rate of Return – RUCO recommends that the Commission adopt a 7.30 percent weighted average cost of capital as the original cost rate of return for TEP. This compares to the Company's requested weighted average original cost of capital of 7.88 percent.

Fair Value Rate of Return – RUCO recommends that the Commission adopt a fair value rate of return of 5.20 percent for TEP, which is RUCO's 6.76 percent original cost rate of return minus RUCO's recommended fair value adjustment of 1.56 percent.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is Robert B. Mease. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. Attachment I, attached to this testimony, describes my educational background, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in October of 2011. I graduated from Morris Harvey College in Charleston, WV and attended Kanawha Valley School of Graduate Studies. I am a Certified Public Accountant ("CPA") and currently licensed in the state of West Virginia, as well as a Certified Rate of Return Analyst ("CRRA"). My years of work experience include serving as Vice President and Controller of Energy West, Inc. a public utility and energy company located in Great Falls, Montana. While with Energy West I had responsibility for all utility filings and participated in several rate case filings on behalf of the utility. As Energy West was a publicly traded company listed on the NASDAQ Exchange I also had responsibility for all filings with the Securities and Exchange Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present RUCO's recommendations for the establishment of a fair value rate of return.

Q. Is this your first case involving TEP?

A. No. I participated in TEP's most recent rate application filed for the test year ended December 31, 2011, and performed an analytical review of the Company's financial schedules that were included in their rate application.[1]

Q. Can you please briefly describe TEP and its ownership structure and customer base?

A. TEP is a wholly-owned subsidiary of UniSource Energy Services, a holding company owned by UNS Energy Corporation. In August of 2014 UNS Energy Corporation was purchased by Fortis, Inc. ("Fortis"). Fortis is an investor owned utility based in St. John's, Newfoundland and Labrador, Canada. TEP's customer base is comprised of approximately 415,000 customers of which 90 percent are residential, approximately 9 percent commercial and the remaining 1 percent industrial.

[1] See Docket No. E-01933A-12-0291; Decision No. 73912

Q. Has TEP elected to perform a reconstruction cost new less depreciation study in this case?

A. Yes. TEP performed a reconstruction cost new less depreciation ("RCND") study and is proposing a fair value rate base ("FVRB") that is an average of the Company's original cost rate base ("OCRB") and its RCND rate base for ratemaking purposes. For this reason RUCO is recommending a fair value rate of return ("FVROR") to be applied to TEP's FVRB.

Q. Please explain your role in RUCO's analysis of TEP's Application.

A. I reviewed TEP's Application and performed a cost of capital analysis to determine both an original cost rate of return ("OCROR") and a fair value rate of return ("FVROR") on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended cost of common equity and my recommended cost of debt. The recommendations contained in this testimony are based on information obtained from TEP's Application, responses to data requests, and from market-based research that I conducted during my analysis.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis, I am making the following recommendations:

<u>Cost of Equity Capital</u> – I am recommending that the Commission adopt a 9.20 percent cost of common equity. This 9.20 percent figure is the result obtained from my cost of equity analysis.

<u>Cost of Debt</u> – RUCO is recommending that the Commission adopt the Company's end of test year cost of long-term debt of 4.32 percent. This compares favorably to the Company's previous rate application where the cost of long-term debt was approved at 5.18 percent.

<u>Capital Structure</u> – I am recommending that the Commission adopt TEP's actual end of test year capital structure comprised of 50.03 percent common equity and 49.97 percent long-term debt. The Company has no short-term debt.

<u>Original Cost Rate of Return</u> – I am recommending that the ACC adopt a 7.30 percent weighted average cost of capital as the original cost rate of return ("OCROR") for TEP. This 7.30 percent figure is the weighted cost of RUCO's recommended costs of common equity and debt, and is 58 basis points lower than the 7.88 percent weighted average cost of capital being proposed by the Company.

<u>Fair Value Rate of Return</u> – I am recommending that the Commission adopt a fair value rate of return ("FVROR") of 5.20 percent which is my

recommended 6.76 percent OCROR minus an inflation adjustment of 1.56 percent.

Q Why do you believe that RUCO's recommended 7.30 percent OCROR and 5.20 percent FVROR are appropriate rates of return for TEP to earn on its invested capital?

A. Both the OCROR and FVROR figures that I am recommending for TEP meet the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (320 U.S. 391, 1944). These two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk. It should be noted that neither case guarantees a rate of return on a utility investment, the cases provide a utility with an opportunity to earn an appropriate return.

GENERAL ECONOMIC CONDITIONS

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. The cost of capital is determined in part by the current and future economic and financial conditions. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, the state of the business cycle and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities. While there are other factors involved in when determining the cost of capital these are the most important factors used in my evaluation.

Q. Can you describe the recent trends in economic conditions and their impact on capital costs over the past thirty years?

A. Yes. Since the early 1980's through the end of 2007 the United States economy had been relatively stable. This period had been characterized by longer economic expansions, small contractions, low and/or declining inflation, and declining interest rates and other capital costs. However, in 2008 and 2009, the economy declined as a result of the mortgage crisis and had a negative effect on the financial markets both in the US and international financial markets. This decline was described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." Since 2008, the U.S. and other country governments implemented unprecedented actions to attempt to correct or minimize the scope and effects of this worldwide recession.

The recession bottomed out in mid-2009 and the economy began to slowly expand again, initially at a slow rate but has escalated at a much quicker rate. This is evidenced by the unemployment rate reducing from 7.4 at the end of 2013 to 5.3 percent at the end of December, 2015. Arizona's unemployment rate hasn't recovered quite as well as the national average and at the end of December, 2015 was 5.8 percent. The length of this most recent recession and the slow recovery indicate that the impact may be felt for an extended period of time.[2]

Q. Can you please describe how the economic and financial indicators were examined and how they relate generally to the cost of capital?

A. Schedule RBM-8 identifies relevant economic data such Gross Domestic Product ("GDP"), Industrial Production Growth, Unemployment, Consumer

[2] United States Department of Labor, Bureau of Labor Statistics, Arizona Unemployment Rate http://www.bls.gov/eag/eag.az.htm

Price Index ("CPI") and Producer Price Index. These schedules also show that 2007 was sixth year of economic expansion and the economy entered into a significant decline as indicated in the GDP negative expansion for year 2008 and the increase in unemployment rates. Since 2010, the economy began to rebound, however, overall economic growth continues to be slower than the initial period of prior expansions.

Since 2008, the CPI has been 3 percent or lower, with 2014 being only 1.1 percent, while 2015 was less than 1. The annual rate of inflation has generally been declining over the past several business cycles and continues as evidenced by 2014 annual inflation rate of 1.7 percent and the 2015 rate of inflation being less than 1 percent. The current levels of inflation are at the lowest levels over the past 35 years and are indicative of lower capital costs.

Q. Over the next 10 year period, is inflation expected to remain at relatively low levels?

A. Yes. In a report issued by the Federal Reserve Bank of Cleveland, the latest estimate of 10 year expected inflation is 1.71 percent.[3]

[3] Federal Reserve Board of Cleveland, "Inflation Expectations," (News Release dated April 14, 2016).

Q. How does the 10 year (2016 – 2025) projected 1.71 percent annual rate of inflation compare to the 10 year historical annual average rates of inflation over the past forty years (1976 – 2015)?

A. The inflation rates over the past forty years in ten-year increments are as follows:

Historical annual rate of inflation (1976 – 1985) 7.05%
Historical annual rate of inflation (1986 – 1995) 3.04%
Historical annual rate of inflation (1996 – 2005) 2.53%
Historical annual rate of inflation (2006 – 2015) 1.86%
Projected annual rate of inflation (2016 – 2025) 1.71%

As shown above, historical annual inflation has fallen in each of the last four 10 year periods. The trend is expected to continue as evidenced by the annual inflation rate for the period of 2016 – 2025 that is projected to be 15 basis points lower than the most recent ten year period.

Q. Assuming all other factors remain constant, does a projected annual inflation rate of 1.71 percent over the next 10 year period suggest that the current low interest rate environment will continue into the future?

A. Yes. Holding all other factors constant interest rates would be expected to remain at the current low levels into the future.

Q. What have been the trends in interest rates over the four prior business cycles and at the current time?

A. Schedule RBM-8 shows that interest rates rose sharply to record levels in 1975-1981, when the inflation rate was high and generally rising. Interest rates declined substantially as did inflation rates during the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and for the years 2009 through 2014, interest rates have been the lowest since prior to 1975. Since 2008, the Federal Reserve has lowered the Federal Funds rate in 2012 and 2013 both U.S. and corporate bond yields declined to their lowest levels in more than 35 years. Interest rates have risen slightly from those lows since the beginning of 2013. Even with the recent increases, both government and corporate lending rates remain at historically low levels through 2014, and have continued through year 2015.

On December 15, 2015, the Federal Government raised the Federal Funds rate from a level of 0 to ¼ percent to ¼ to ½ percent. Since this rate increase yields on U.S. Treasury Securities have fallen due to a higher demand on fixed income investments. This also suggests that today's low interest rate environment will continue into the future.

Q Did the action taken by the Feds to raise the Fed Funds rate in December 2015 signal a change in monetary policy by the U.S. Central Bank?

A. No. It did not. While the increase in the Fed Funds rate marked the first time the Feds has increased the rates charged to banks for overnight transfers of funds since mid-2006, in a press release issued on December

16, 2015, made the following statement: "The stance of monetary policy remains accommodative after this increase, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.[4]

Q. What do the economic indicators show for trends of common share prices?

A. Schedule RBM-8, shows that stock prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. Beginning in 1983 a significant upward trend in stock prices began. However, the beginning of the recent financial crisis saw stock prices decline significantly and stock prices in 2008 and early 2009 were down significantly from peak 2007 levels, reflecting the financial/economic crisis. Beginning in the second quarter of 2009, prices have recovered substantially and have ultimately reached and exceeded the levels achieved prior to the beginning of the "crash" and the DOW Jones Industrial average has reached all-time highs in the fourth quarter of 2015. Following the action taken by the Fed to raise the Fed Funds rate, the equity markets experienced a sell-off, but all three major stock indices have since risen from their lows of February 11, 2016.[5]

[4] Federal Reserve Board, Federal Open Market Committee, Press Release (December 16, 2015). http://www.federalreserve.gov/newsevents/press/monetary/20151216a.htm

[5] February 11, 2016, the DJIA closed at 15,660.18; the S&P 500 closed at 1,829.08; and NASDAQ closed at 4,266.84. On May 3, 2016, these markets closed at 17,750.91; 2063.37; and 4,763,22, respectively.

Q. Is it possible that the U.S. economy could fall into recession in late-2016?

A. Yes. Research analysts at City Group forecast a 65 percent probability of the U.S. economy entering into recession later during year 2016. (Recession – defined as two consecutive quarters of shrinking economic growth)[6] As another observer has expressed, "[t]he odds of a recession may be less than 50%, but not by much. And in 2017, the odds shift."[7]

Q. What conclusions can be reached from your discussion of economic and financial conditions?

A. While the economy is recovering from this latest recession, it is recovering slower than expected. Slower recovery means that the results of the traditional cost of equity models are lower than prior to the recession. Despite the Federal Reserve having raised the Fed Funds rate in December, 2015, it is believed by many economic forecasts that the probability of continued rate hikes in 2016 and 2017 to be low. Chairperson Yellen has indicated a willingness to raise short-term interest rates in the event the U.S. economy should return to a recession, and should circumstances warrant additional monetary policy accommodation. Chairperson Yellen, also indicated a willingness to consider use of negative

[6] Sherter, Alan, "Will the U.S. Economy Slip into Recession in 2016?," Money Watch (December 23, 2015). http://www.cbsnews.com/news/will-the-u-s-economy-slip-into-recession-in-2016/
[7] Murray, Alan. "Is 2016 the Year of the Next Recession?," Fortune.com (Jan. 11, 2016) http://fortune.com/2016/01/11/stock-market-recession-2016/

interest rates if necessary. Even though the U.S. economy is stronger today than the past seven year recession, expected investment returns have declined since the beginning of the Great Recession of 2008, and given the current economic uncertainty in going forward there is good reason to believe that interest rates will remain at or near the current levels for the next several years.

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery. During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties. According to information published on October 30, 2015, the seasonally adjusted unemployment rate for Arizona has increased from 6 percent in April, 2015, to 6.3 percent in September, 2015. This compare the national unemployment rate of 5.1 percent for the period ending in September, 2015. I believe it is safe to say that Arizona's economy is recovering at a much slower pace that the national average.

ECONOMIC ENVIRONMENT – ELECTRIC UTILITIES SPECIFIC

Q. Does it appear that investor-owned electricity companies, as well as the utility sector in general, performed well in 2014 and 2015?

A. Yes. In reviewing Edison Electric Institute's (EEI) 2014 Financial Review as published in their Annual Report of the U.S. Investor-Owned Electric Utility Industry, the electric companies are performing very well. For year 2015 the industry continue to perform well. This is evidenced by a message included as part of the Presidents Letter when he stated; "The industry's dividend yield at the end of 2015 stood at 3.8 percent, and 39 utilities, or 85 percent of the industry, increased their dividend last year, the largest percentage on record."[8] The annual report went on to point out the "Industry's dividend payout ratio was 61.3% for the year ended December 31, 2015, remaining among the highest of all U.S. business sectors."[9]

Q. Can you please describe the EEI organization, and how that organization serves the electric utility industry?

A. Yes. EEI's mission is to ensure member's success by advocating public policy, expanding market opportunities, and proving strategic business information. EEI is an association that represents all U.S. investor-owned electric companies. Their members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and employ

[8] EEI 2015 Financial Review; Page 1, President Letter
[9] EEI 2015 Financial Review; Page 21

more than 500,000 workers. The proxy companies that we chose in our analysis are all members of EEI. UNSE is also a member of EEI. In addition, EEI has seventy international companies as Affiliate Members and 250 industry suppliers and related organizations as Associate Members.

Q. Can you please describe the purpose of EEI's Financial Review as discussed in the prelude to Edison Electric Institute's annual report?

A. Yes. EEI's Financial Review is a source for critical financial data covering 47 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges and also includes data on six additional companies that provide regulated electric service but are not listed on U.S. stock exchanges.

Q. Briefly identify the 2014 financial highlights as presented in the Presidents Letter included in the 2014 Financial Review.

A.

> "In 2014, the EEI Index returned an average of 28.9 percent, compared to the 10.0 percent return posted by the Dow Jones Industrial Average and the S&P 500's 13.7 percent return. For 10 years ending December 31, 2014, The EEI Index's 156 percent return outpaced the Dow Jones Industrial's 114 percent return and S&P's 110 percent return."

> "The industry's average credit rating improved to BBB+ from BBB, the first change since 2004 when it increased from BBB-, as individual company ratings were overwhelmingly positive in 2014."

> "The industry's dividend yield at the end of 2014 stood at 3.3 percent, and 38 utilities, or 79 percent of the industry, increased their dividend yield last year, the largest percentage on record."

Q. Did EEI publish information on rate case applications that member companies have been involved in for year 2014?

A. Yes. Investor-owned electric utilities filed 58 rate cases in 2014. The average requested ROE was the lowest requested in their history and the awarded ROE was the lowest in their data bank reaching back to 1990.

Q. Has there been updates published by EEI for rate case activity related to investor-owned members for year 2015?

A. Yes. The Rate Case Summary report issued by EEI for 2015 stated that the average awarded ROE continued to be at record lows and consistent with the downward trend extending over more three decades. In addition, investor-owned electric utilities filed 48 new rate cases in 2015, the lowest annual total in seven years. Also, while the average requested ROE in 2015 was a record low, the average awarded ROE was also the lowest in more than three decades.[10]

COST OF DEBT AND CAPITAL STRUCTURE

Q. What cost of long-term debt are you recommending for TEP?

A. I am recommending that the Commission adopt TEP's actual end of test year cost of long-term debt of 4.32 percent.

[10] EEI 2015 Financial Review; Page 25

Q. Please describe the Company-proposed capital structure.

A. The Company is proposing an adjusted end of test year capital structure comprised of no short-term debt, 49.97 percent long-term debt and 50.03 percent common equity.

Q. How does the Company-proposed capital structure compare with the capital structures of the electric companies that comprise your sample?

A. The Company-proposed capital structure is very similar to the average capital structure of the electric companies included in my sample.

Q. What capital structure are you recommending for TEP?

A. I am recommending that the Commission adopt the Company's actual end of test year capital structure comprised of zero short-term debt, 49.97 percent long-term debt and 50.03 percent long-term common equity, which is essentially the same as the capital structure being proposed by TEP.

RUCO's COST OF EQUITY RECOMMENDATIONS

Q. What is your final recommended cost of equity capital for TEP?

A. I am recommending a cost of equity of 9.20 percent. My recommended 9.20 percent cost of equity is the high side of the range of results derived from my DCF, CAPM and Comparable Earnings ("CE") analyses, which utilized a sample of publicly traded electric companies.

Discounted Cash Flow (DCF) Method

Q. Is the DCF model an acceptable methodology used in ratemaking for public utilities?

A. Yes. Basically the DCF model, is one of the oldest and most utilized models in determining the cost of equity in many utility hearings. In a 2014 rate case filing by Potomac Electric Power, in Washington, D.C., the commission relied primarily on a DCF analysis to arrive at the authorized ROE, "finding that the DCF method produces results more reasonable than those of other calculation methods."[11]

Q. You stated that the commission "primarily" relied on the DCF model, should this model be relied upon exclusively in determining a utilities ROE?

A. No. While the DCF model is the most widely used and accepted model, including Arizona, it should be supplemented with additional models or calculations (i.e. CAPM model, risk assessment, comparable earnings assessment etc.) to add support to the final cost of equity analysis. The various models will produce different results depending on the economic conditions and inputs included in calculating the results. It is important to look at, and include in the final cost of equity results, these alternative

[11] See EEI 2014 Annual Report, page 29

calculations to determine the reasonableness of the individual and overall final results.

Q. Please explain the DCF method that you used to estimate the Company's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model. This model is frequently referred to as the Gordon model. This DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

The DCF formula basically recognizes that the expected return, or required return, by investors is comprised of the current dividend yield, and expected growth in dividends.

Q. In determining the rate of future dividend growth for the Company, what assumptions did you make?

A. There are two basic assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group comprised of twelve publicly traded electric service providers.

Q. Why would you use a proxy group methodology as opposed to a direct analysis of the Company?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company. Although TEP's ultimate parent company, Fortis, Inc., is publicly traded on the Toronto, Canadian Stock Exchange, TEP is not. Because of this situation, I used a proxy group that includes twelve electric utilities with similar risk characteristics as TEP in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. The U.S. Supreme Court ruled in Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944) that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy methodology used by most cost of equity analysts derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. **Are these the same electric providers included in the proxy used by TEP's cost of equity witness?**

A. No. RUCO's proxy group selected was similar to that of TEP, but eliminated two power companies that have been acquired, or in the process of being acquired. Each of the electric utilities included in our respective samples are tracked in the Value Line Investment Survey's ("Value Line") Electric Utility industry segment. Value Line follows electric utilities on a regional basis and issues quarterly updates on electric utilities located in the eastern, central and western portions of the U.S. All of the companies in the proxy are engaged in the provision of regulated electric services. EXHIBIT 1 of my testimony contains Value Line's most recent evaluation on each of the companies that are included in the electric proxy group that I used for my cost of common equity analysis.

Capital Asset Pricing Model (CAPM) Method

Q. **Can you please describe the CAPM and the benefits of preparing this analysis?**

A. The CAPM describes the relationship between a security's investment risk and its market rate of return. This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk. The relationship is specified by the Security Market Line (SLM) that indicates the relationship between each security or portfolio's "beta" and its resulting return. Beta is an indicator of investment risk. It is a measure of the expected amount of change in a security's variability of return relative to the return variability of the overall capital market. The general form of the CAPM is:

$$K = R_f + \beta\,(R_m - R_f)$$

Where: K = *cost of equity*

R_f = *risk free rate*

R_m = *return on market*

β = *beta*

$R_m - R_f$ = *market risk premium*

Q. Can you please identify the strengths of using the CAPM model in your analysis?

A. The strengths of the CAPM are as follows: (1) it is based on the concept of risk and return; (2) it is company specific as it relates to the specific beta's within the industry; (3) it has widespread use as it recognizes that investors can and do diversify; (4) it's highly structured and easy to apply when using the assumptions of the model; (5) the model is formulistic and the data used in the computations is readily available; (6) it is a forward looking concept;

and (7) it is a method for converting changes in interest rates to the cost of equity.

Q. What do you use for the risk-free rate?

A. The risk-free rate is generally recognized by use of U.S. Treasury securities in CAPM applications. Two general types of U.S. Treasury securities are most often used as the risk free *(Rf)* component, short-term U.S. Treasury bills and long-term U.S. Treasury bonds. I performed my CAPM calculations using three-month average yield (February through April 2016) for 30-year U.S. Treasury bonds. The yields on long-term Treasury bonds are used since this matches the long-term perspective of the cost of equity analyses. Over this three-month period, these bonds had an average yield of 2.64 percent.

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. Investors would like to believe that U.S. Treasury securities pose no threat of default no matter what their maturity dates are as the United States Government backs them. However, even when using Treasury instruments those with longer maturity dates do have slightly higher yields. When an investor locks up funds in long-term T-Bonds, the investor must be compensated for the future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). This compensation translates into higher rates of returns to the investor.

Q. What betas do you employ in your CAPM?

A. Once again, beta[12] is a measure of the relative volatility, or risk, of a particular stock in relation to the overall market. Betas less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. The most recent Value Line betas have been used in my analysis for each company in my proxy group.

Q. What are the results of your CAPM analysis?

A. As shown on RBM-6, my CAPM results in an average expected return of 7.97 percent.

<u>Comparable Earnings ("CE") Model</u>

Q. Can you please describe the CE methodology?

A. The CE model is designed to measure returns expected to be earned on the original cost book value of similar utilities that are publicly traded companies. In this case, RUCO's proxy group of companies provide a

[12] See Exhibit 1 – Individual proxy companies beta's identified

direct measure of the fair return since it translates into practice the competitive principle which regulation exists.

Q. How did RUCO apply the CE model results into the results obtained in this case?

A. RUCO examined returns on equity achieved by the proxy companies over a 14-year period historical period (2002 - 2015), as well as projected returns on equity for future years 2016, 2017, and 2019 – 2021.

Q. What is RUCO's final results when performing a CE analysis?

A. RUCO determined that comparable earnings of the twelve proxy companies included in our sample, for the period identified, was a range of 7.91 percent to 9.30 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	7.91% - 9.65%
CAPM	7.97%
CE	8.50% - 9.30%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 7.91 percent to 9.65 percent. My final recommended cost of common equity is 9.20 percent and is slightly higher than the average of the DCF, CAPM, and CE calculations. See RBM-3 for calculations.

Q. Can you provide a comparison of the results derived from Ms. Bulkley's models and yours?

	Company Witness	RUCO
DCF – Constant Growth	9.04% – 10.35%	7.91% – 9.65%
DCF -- Multi-Stage	9.30% -- 9.92%	
CAPM	9.59% -- 11.10%	7.97%
Risk Premium	9.70% -- 10.72%	
Comparable Earnings		8.50% -- 9.30%

TEP's PROPOSED COST OF EQUITY CAPITAL

Q. Have you reviewed TEP's testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony of the Company's cost of equity expert witness, Ms. Ann Bulkley.

Q. Please compare the Company-proposed cost of equity with your recommended cost of equity.

A. The Company is recommending a cost of equity capital of 10.35 percent which is 115 basis points higher than my recommended 9.20 percent cost of equity.

Q. Can you explain the primary differences behind the 115 basis point spread between the Company's ROE and the RUCO's calculations?

A. Yes I will. The primary difference is reflected in Ms. Bulkley's use of forward looking estimates only as opposed to the use of both historical and forward looking estimates. As she states in her testimony "The required ROE should be forward looking estimate; therefore, the analyses supporting my recommendation should rely on forward looking inputs and assumptions (e.g., projected growth rates in the DCF model, forecasted risk-free rate and Market Risk Premium in the CAPM analysis, etc.) and takes into consideration the current high valuations of utility stocks and market's expectations for higher interest rates."[13]

[13] See Ms. Bulkley's testimony, page 7

Q. Do you concur with Ms. Bulkley's assessment and her use of only forward looking inputs only?

A. No I don't and neither does the Arizona Corporation Commissioners. Decision No. 75265, issued on September 8, 2015, states the following, "EPCOR is also critical of RUCO's use of historical data in evaluating cost of equity, which the Company claims should be a forward-looking analysis. However, we believe that consideration of both historical and projected data is appropriate in evaluating cost of equity."[14]

Q. Does Ms. Bulkley reference Blue Chip Financial Forecasts as one of her main inputs used in her CAPM analysis?

A. Yes. Ms. Bulkley references Blue Chip Financial Forecasts several times during her testimony. When preparing her CAPM analysis she states that that she has relied on three sources for estimating the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds (i.e. 3.09 percent) as published by Bloomberg Professional; (2) the projected 30-year U.S. Treasury bond yield for 2015 through 2016 of 3.57 percent; and (3) the projected 30-year U.S. Treasury bond yield for 2017 through 2021 of 4.80 percent as projected by Blue Chip Financial.[15]

[14] See EPCOR Water Arizona, Inc., Decision No. 75268
[15] See Ann E. Bulkley testimony, Page 38

Q. Does RUCO question the use of projections based on 30-year bond ratings going forward?

A. Yes. RUCO questions the use of 30-year Treasury bond projections as published by Blue Chip Financial. According to a report published by the Executive Office of the President of the United States, published in July 2015, page 10; "Past forecasts have largely missed the decline in long-term interest rates. This can be seen in Figure 5, which shows past private-sector forecasts along with the actual path of nominal 10-year Treasury rates since 1995."[16] The differences in projected 10-year Treasury Rates and Historical Economist Forecasts as shown on the attached Exhibit --- vs. the actual are as follows:

Year	Projected 10 year forecast	Actual End of Period
1996	6.2 %	4.0 %
2000	5.8 %	3.3 %
2005	5.4 %	2.2 %
2010	5.4 %	2.2 %

As shown in the above as well as the attached Exhibit, Blue Chip Forecasters have not been, reliable when it comes to forecasting future projected interest rates. Although economists' forecasts steadily declined after 1995, their pace of decline has lagged well behind the realized drop-off in interest rates.

[16] See Exhibit 4, Pages 10 and 11 of the report published by Executive Office of the President of the United States

Q. Are there other reasons that you can identify that created the 115 basis point differential?

A. Yes. There are several reasons that ROE's are substantially different.

(1) As Ms. Bulkley explaied in her testimony she considered several additional risk factors that affect the Company's ROE: (i) the Company's capital expenditure requirements, and (ii) the regulatory environment in which the Company operates. Finally, I considered the Company's proposed capital structure compared to the capital structures of the proxy companies. While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results."[17]

(2) Included in the Company's testimony is a calculation described as Bond Yield Plus Risk Premium Analysis. As described in Ms. Bulkley's testimony "this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated to bear that risk."

[17] See Ann E. Bulkey's testimony, Page 3

Q. As a follow up to Ms. Bulkley's response to the previous question and her comments related to risk premium for small companies, has the ACC addressed this in previous decisions?

A. Yes. In Decision No. 75268, the Commission made the following findings; "Although a company's size may sometimes be considered as a business risk factor, for utilities of substantial size, (those having access to capital markets) it is a minimal consideration in determining business risk. Small utilities (e.g., non-class A utilities) may have substantial risk due to the inability to hire employees or contract for sufficient levels of expertise (management, technical & financial) to perform effectively and efficiently. Small utilities also have other risks such as information access, greater annual variability in operating expenses, and greater regulatory risk both due to lack of skilled rate case personnel and the percentage of operating expenses and rate base components reviewed by Staff and intervenors. Due to the latter two reasons, for any adopted return on equity the distribution of actual returns is greater for small utility than for a large utility, and greater variability means greater risk. However, most of the proxy companies used in the cost of capital analyses, including EPCOR, are a conglomeration of many smaller water systems and have the capacity to attract the appropriate level of talent for proficient operation. Thus, the business risk of the EPCOR systems parallels that that of the sample companies, and <u>we do not believe a cost of equity adjustment for size is appropriate.</u>"

Q. What methods did the Company witness, Ms. Bulkley, use to arrive at her cost of common equity for TEP compared to the models as prepared by RUCO?

A. Ms. Bulkley used the constant growth DCF model and a multi-stage DCF. In addition, she also employed both the CAPM and risk premium methods to estimate TEP's final cost of common equity. I have prepared both a DCF and CAPM models since the Commission has traditionally placed more weight on the results of these two models. I also prepared a Comparable Earnings model as the CAPM model is producing relatively low results as low interest rates significantly affect the results of this model.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 10.35 percent cost of equity capital proposed by the Company is 115 basis points higher than the 9.20 percent cost of equity capital that I am recommending.

WEIGHTED COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. What original cost weighted average cost of capital are you recommending for TEP?

A. Based on my recommended capital structure, comprised of 49.97 percent long-term debt and 50.03 percent common equity, I am recommending an original cost weighted average cost of capital of 7.34 percent, Schedule RBM-1. This is the weighted average cost of my recommended cost of long-term debt of 4.32 percent and my recommended 9.20 percent cost of common equity.

Q. What fair value rate of return are you recommending for TEP?

A. I am recommending a FVROR of 5.20 percent, RBM-1, which is 156 basis points lower than my OCROR of 6.76 percent. My recommended FVROR satisfies the fair value requirement of the Arizona Constitution which the Commission must follow when setting rates for investor owned utilities such as TEP.

Q. Why are you recommending a FVROR that is different from your OCROR?

A. Because TEP elected not to use the Company's original cost rate base ("OCRB") as its fair value rate base ("FVRB") in this case. Instead, TEP performed a reconstruction cost new less depreciation ("RCND") study to restate the value, or reproduction cost, of the Company's OCRB. As is the normal ratemaking practice in Arizona, the Company averaged the values of its OCRB and its RCND rate base to arrive at a FVRB that is higher than the OCRB. This is because the value of the FVRB reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Since the difference in the value of the OCRB and the

FVRB represents inflation, as opposed to additional investor supplied capital, an OCROR which includes an inflation component cannot be applied to the FVRB. To do so would result in a double counting of inflation. For this reason it is necessary to remove the inflation component that is included in the OCROR.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Ms. Bulkley or any other witness for TEP constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on TEP?

A. Yes, it does.

ATTACHMENT

ROBERT B. MEASE, CPA, CRRA
Education and Professional Qualifications

EDUCATION

Bachelors Degree Business Administration / Accounting - Morris Harvey College.

Attended West Virginia School of Graduate Studies and studied Accounting and Public Administration

Attended numerous courses and seminars for Continuing Professional Educational purposes.

WORK EXPERIENCE

Controller
Knives of Alaska, Inc., Diamond Blade, LLC, and Alaska Expedition Company.

Financial Manager / CFO
All Saints Camp & Conference Center

Energy West, Inc.
Vice President, Controller

- Led team that succeeded in obtaining a $1.5 million annual utility rate increase
- Coached accountants for proper communication techniques with Public Service Commission, supervised 9 professional accountants
- Developed financial models used to negotiate an $18 million credit line
- Responsible for monthly, quarterly and annual financial statements for internal and external purposes, SEC filings on a quarterly and annual basis, quarterly presentations to Board of Directors and shareholders during annual meetings, coordinated annual audit
- Communication with senior management team, supervised accounting staff and resolved all accounting issues, reviewed expenditures related to capital projects
- Monitored natural gas prices and worked with senior buyers to ensure optimal price obtained

Junkermier, Clark, Campanella, Stevens
Consulting Staff

- Established a consulting practice that generated approximately $160k the first year of existence
- Prepared business plan and projections for inclusion in clients financing documents
- Prepared written reports related to consulting engagements performed
- Developed models used in financing documents and made available for other personnel to use
- Performed Profit Enhancement engagements
- Participated during audit of large manufacturing client for two reporting years

Prior to 1999, held various positions: TMC Sales, Inc. as **Vice President / Controller**, with American Agri-Technology Corporation as **Vice President / CFO** and with Union Carbide Corporation as **Accounting Manager. (Union Carbide was a multi-national Fortune 500 Company that was purchased by Dow Chemical)**

PROFESSIONAL AFFILIATIONS
Past Member - Institute of Management Accountants
Member - American Institute of CPA's
Member – Society of Utility and Regulatory Financial Analysts
Past Member –WV Society of CPA's and Montana Society of CPA's

RESUME OF RATE CASE AND REGULATORY PARTICIPATION WITH RUCO

Utility Company	Docket No.
Arizona Water Company (Eastern Group)	W-01445A-11-0310
Pima Utility Company	W-02199A-11-0329 et al.
Tucson Electric Power Company	E-01933A-12-0291
Arizona Water Company (Northern Group)	W-01445A-12-0348
UNS Electric	E-04204A-12-0504
Global Water	W-01212A-12-0309 et al.
LPSCO	SW-01428A-13-0042 et al.
Johnson Utilities	WS-02987A-13-0477
Johnson Utilities	WS-02987A-08-0180
APS	E-01345A-11-0224
EPCOR Water Arizona, Inc.	WS-01303A-09-0343
Utility Source, LLC	WS-04235A-13-0331
EPCOR Water Arizona, Inc.	WS-01303A-14-0010
EPCOR Water, Purchase of Willow Valley Water, Co.	W-01732A-15-0131
UNS Electric	E-04204A-15-0142

EXHIBIT 1

ALLETE NYSE-ALE

RECENT PRICE 55.56 | P/E RATIO 17.5 (Trailing: 16.5 Median: 16.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 4/24/15

SAFETY 2 New 10/1/04

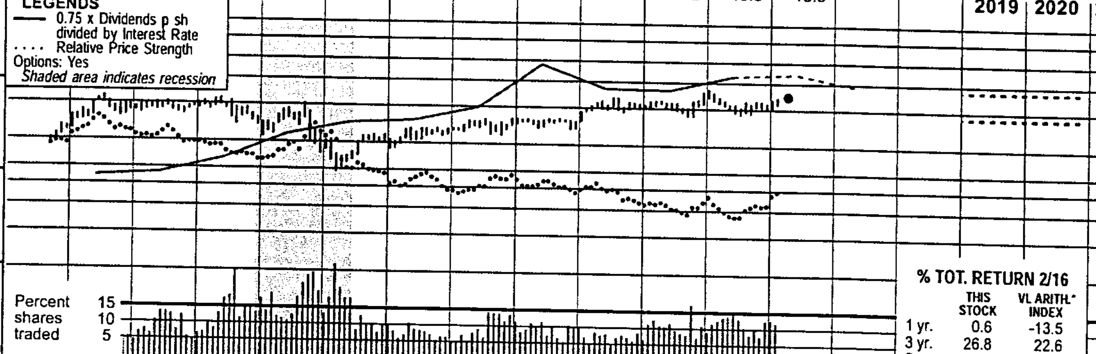
TECHNICAL 2 Raised 3/11/16

BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	55.9
Low:	35.7	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3

LEGENDS
— 0.75 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	6%
Low	45	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	1	0	0	0	0	7
to Sell	1	1	0	3	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	117	90	121
to Sell	79	100	83
Hld's(000)	35643	35552	35280

Percent shares traded 15 10 5

% TOT. RETURN 2/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.6	-13.5
3 yr.	26.8	22.6
5 yr.	72.5	38.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
--	--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	*27.35*	*28.15*	Revenues per sh	*30.50*
--	--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	*6.80*	*7.15*	"Cash Flow" per sh	*8.25*
--	--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	*3.20*	*3.35*	Earnings per sh A	*3.75*
--	--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	*2.08*	*2.14*	Div'd Decl'd per sh B ■ †	*2.40*
--	--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	*3.95*	*5.65*	Cap'l Spending per sh	*3.50*
--	--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	*38.25*	*39.50*	Book Value per sh C	*43.25*
--	--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	*49.40*	*49.70*	Common Shs Outst'g D	*51.00*
--	--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
--	--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.77	*estimates*		Relative P/E Ratio	*.90*
--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%			Avg Ann'l Div'd Yield	*4.5%*
						767.1	841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	1486.4	*1350*	*1400*	Revenues ($mill)	*1550*
						77.3	87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	163.4	*155*	*165*	Net Profit ($mill)	*190*
						37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
						1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	*45.5%*	*45.0%*	Long-Term Debt Ratio	*42.5%*
						64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	*54.5%*	*55.0%*	Common Equity Ratio	*57.5%*
						1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	*3455*	*3580*	Total Capital ($mill)	*3850*
						921.6	1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	*3685*	*3775*	Net Plant ($mill)	*3825*
						8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
						11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	*8.5%*	*8.5%*	Return on Shr. Equity	*8.5%*
						11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	*8.5%*	*8.5%*	Return on Com Equity E	*8.5%*
						5.0%	5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						57%	51%	61%	93%	81%	66%	71%	72%	67%	60%	*66%*	*64%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $1606.6 mill. Due in 5 Yrs $411.9 mill.
LT Debt $1568.7 mill. LT Interest $63.5 mill.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $14.0 mill.

Pension Assets-12/15 $521.3 mill. Oblig. $709.8 mill.

Pfd Stock None

Common Stock 49,111,849 shs. as of 2/1/16

MARKET CAP: $2.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	-1.1	+.5	-8.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.45	6.09	6.40
Capacity at Peak (Mw)	1793	1985	1942
Peak Load, Winter (Mw) F	1646	1637	1631
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	306	345	381

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	.5%	2.0%	*2.5%*
"Cash Flow"	5.5%	8.0%	*5.5%*
Earnings	4.5%	5.0%	*4.0%*
Dividends	9.5%	2.5%	*3.5%*
Book Value	5.5%	6.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	263.8	235.6	251.0	268.0	1018.4
2014	296.5	260.7	288.9	290.7	1136.8
2015	320.0	323.3	462.5	380.6	1486.4
2016	*330*	*335*	*345*	*340*	*1350*
2017	*350*	*345*	*355*	*350*	*1400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2013	.83	.35	.63	.82	2.63
2014	.80	.40	.97	.73	2.90
2015	.85	.46	1.23	.83	3.38
2016	*.90*	*.45*	*1.00*	*.85*	*3.20*
2017	*.95*	*.45*	*1.05*	*.90*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.46	.46	.46	.46	1.84
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	2.02
2016	.52				

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 51%; wind, 11%; other, 3%; purchased, 35%. Fuel costs: 22% of revs. '15 deprec. rate: 3.3%. Has 1,600 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's earnings in 2015 are a tough act to follow. In the second half of last year, the sale of a wind project ALLETE Clean Energy built for a utility in North Dakota boosted the top line by $197.7 million and contributed $0.42 a share to the bottom line. Management's earnings guidance for 2016 is $3.10-$3.40 a share, so profits will probably fall short of the 2015 tally. Our estimate of $3.20 a share is within this range.

The company's Minnesota Power subsidiary faces some challenges. In the past few months, the utility's taconite mining customers in aggregate have run at just 80% of capacity, and they don't expect this to change through this summer. (Taconite is used in steelmaking.) Minnesota Power would like to address rate design so that its tariffs for large industrial customers are lower and more reflective of the cost to serve them, but the state regulators turned down its proposal. The utility has done an effective job of reducing costs, but is still not earning its allowed return on equity. The filing of a general rate case is possible.

Earnings should rebound in 2017. Construction of a $345 million transmission project between northern Minnesota and Manitoba is expected to begin next year. The utility receives a current return on certain kinds of capital spending, including transmission. Our earnings forecast would produce 5% growth, which is ALLETE's annual goal.

ALLETE has changed its strategy regarding its real estate operation. ALLETE Properties has not been a core business for several years, and the company has attempted to sell its holdings gradually. However, management is now exploring the possibility of selling the entire operation at once. Accordingly, the company took a writedown of $0.46 a share in the fourth quarter of 2015. The book value of ALLETE Properties is now $50 million. It is a modest drag on corporate profits.

As usual, the directors raised the dividend in the first quarter. The annual increase was $0.06 a share (3.0%). ALLETE's targeted payout ratio is 60%-65%.

ALLETE's dividend yield and 3- to 5-year total return potential are close to those for the utility industry.

Paul E. Debbas, CFA *March 18, 2016*

(A) Diluted EPS. Excl. nonrec. losses: '04, 25¢ net; '05, $1.84; '15, 46¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '15 EPS don't add due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '15: $11.96/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '15: 9.3%. Reg. Clim.: Avg. (F) Summer peak in '13.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

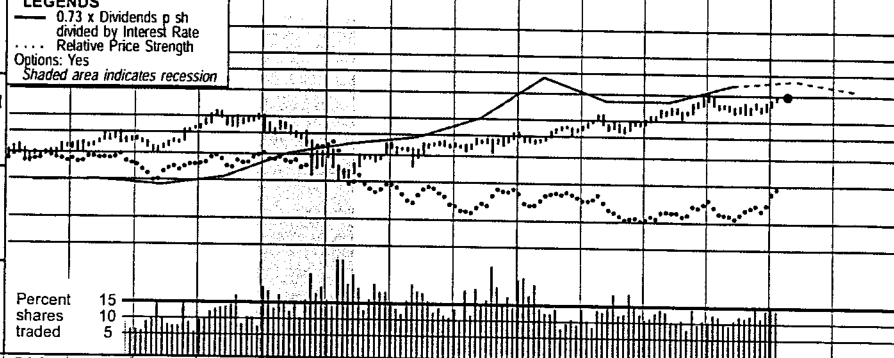
AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE 63.61 | P/E RATIO 17.4 (Trailing: 17.7; Median: 13.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 1 Raised 3/11/16
SAFETY 2 Raised 9/19/14
TECHNICAL 3 Raised 2/26/16
BETA .70 (1.00 = Market)

High:	40.8	43.1	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4	63.9
Low:	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3	56.8

Target Price Range 2019 | 2020 | 2021



128 96 80 64 48 40 32 24 16 12

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+10%)	6%
Low	50	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	10	0	0	0	0	1	0	0	0
to Sell	4	0	0	3	0	0	1	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	327	328	369
to Sell	336	317	323
Hld's(000)	328262	332965	339168

% TOT. RETURN 2/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.4	-13.5
3 yr.	48.4	22.6
5 yr.	113.3	38.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	*33.50*	*34.30*	*35.15*	Revenues per sh	*39.00*
5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	*8.10*	*8.35*	*8.70*	"Cash Flow" per sh	*9.75*
1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.60	*3.70*	*3.85*	Earnings per sh A	*4.25*
2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	*2.27*	*2.39*	Div'd Decl'd per sh B ■	*2.75*
5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	*9.35*	*10.50*	*10.45*	Cap'l Spending per sh	*9.00*
25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	*36.45*	*37.95*	*39.45*	Book Value per sh C	*44.25*
322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	*491.00*	*493.00*	*495.00*	Common Shs Outst'g D	*500.00*
34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	*Value Line*		Relative P/E Ratio	*.90*
6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $20208 mill. Due in 5 Yrs $9052 mill.
LT Debt $17600 mill. LT Interest $792 mill.
Incl. $2114 mill. securitized bonds. Incl. $552 mill. capitalized leases.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $293 mill.
Pension Assets-12/14 $4968 mill.
Oblig. $5225 mill.
Pfd Stock None

Common Stock 490,817,402 shs. as of 10/22/15
MARKET CAP: $31 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
12622	13380	14440	13489	14427	15116	14945	15357	17020	16453	*16900*	*17400*	Revenues ($mill)	*19500*
1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1762.0	*1740*	*1815*	Net Profit ($mill)	*2075*
33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	35.1%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	*10.0%*	*10.0%*	*10.0%*	AFUDC % to Net Profit	*7.0%*
56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	*50.0%*	*49.0%*	*49.5%*	Long-Term Debt Ratio	*49.0%*
43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	*50.0%*	*51.0%*	*50.5%*	Common Equity Ratio	*51.0%*
21902	24342	26290	28958	29184	29747	30823	32913	33001	*35625*	*36800*	*38625*	Total Capital ($mill)	*43300*
26781	29870	32987	34344	35674	36971	38763	40997	44117	46133	*49025*	*51825*	Net Plant ($mill)	*58500*
6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	*6.0%*	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	*10.0%*	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	*10.0%*	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	*4.0%*	*4.0%*	*3.5%*	Retained to Com Eq	*3.5%*
53%	55%	55%	56%	66%	60%	63%	62%	61%	*62%*	*64%*	*65%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.1	-1.5	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.4	+.3
Fixed Charge Cov. (%)	280	326	348

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	-1.5%	--	2.5%
"Cash Flow"	1.5%	1.5%	4.5%
Earnings	1.5%	1.5%	4.5%
Dividends	.5%	4.0%	5.0%
Book Value	4.5%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	3826	3582	4176	3773	15357
2014	4648	4044	4302	4026	17020
2015	4580	3827	4431	3615	16453
2016	*4450*	*4050*	*4450*	*3950*	*16900*
2017	*4600*	*4150*	*4600*	*4050*	*17400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.75	.73	1.10	.60	3.18
2014	1.15	.80	1.01	.38	3.34
2015	1.20	.85	1.04	.41	3.60
2016	*1.20*	*.85*	*1.20*	*.45*	*3.70*
2017	*1.25*	*.90*	*1.25*	*.45*	*3.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.47	.47	.47	.47	1.88
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	2.15
2016	.56				

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric rev. breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 36% of revs. '14 reported deprec. rates (utility): 1.4%-8.6%. Has 18,500 employees. Chairman, President & CEO: Nicholas K. Akins. Inc.: NY. Address: 1 Riverside Plaza, Columbus, OH 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power has reached a settlement in Ohio regarding a purchased-power agreement between its utilities in the state and a portion of its nonregulated generating assets. The company projects that the proposed agreement would save customers $721 million over its eight-year duration (through May of 2024). The staff of the Ohio commission and several intervenors signed the settlement, but the deal still faces significant opposition from owners of nonregulated generating assets in the Midwest. A ruling from the Ohio regulators is expected in late March or early April.

The company might sell its remaining nonregulated generating assets. In recent years, as conditions in the power markets have worsened, AEP has been focusing on the regulated side of its business while de-emphasizing the nonregulated operations. An announcement along these lines is likely once the commission makes its decision on the aforementioned settlement. If the regulators reject the agreement, the sale will include the assets that were designated for it.

Public Service of Oklahoma is awaiting a rate order. The utility is seeking an increase of $177 million, based on a return of 10.5% on a common-equity ratio of 48%. An interim tariff hike of $75 million took effect in January.

The regulated operations are faring well. Most of AEP's utilities are earning at or near their allowed return on equity. The aforementioned rate case in Oklahoma is the only one pending—unusual for this company, which has had frequent regulatory activity in recent years. Electric transmission is a growth area for AEP. Over the next three years, the company's capital budget for transmission is more than $3.5 billion. Our 2016 earnings estimate is within management's targeted range of $3.60-$3.80 a share. We forecast further profit growth in 2017, within AEP's annual goal of 4%-6%.

This timely stock has a dividend yield that is average for a utility. However, with the recent quotation (like that of many utilities) in the upper half of the 2019-2021 Target Price Range, total return potential is unattractive.

Paul E. Debbas, CFA *March 18, 2016*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discont. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢. '14 EPS don't add due to rounding. Next egs. due late Apr. (B) Div'ds historic. paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $17.67/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq., '14: 9.9%. Reg. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	90

EL PASO ELECTRIC NYSE-EE

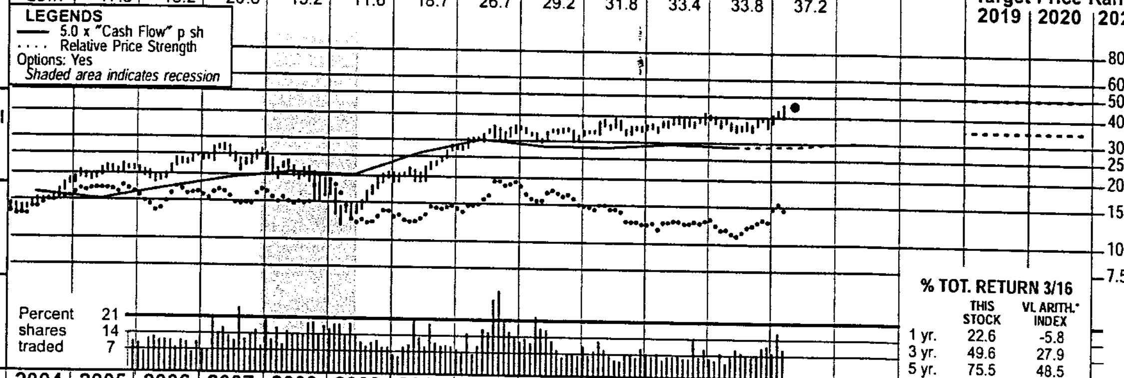
RECENT PRICE 45.41 | P/E RATIO 23.7 (Trailing: 22.4; Median: 15.0) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 2 Raised 4/1/16
SAFETY 2 Raised 5/11/07
TECHNICAL 2 Raised 4/29/16
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3	46.6	
Low:	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2	

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	5%
Low	35	(-25%)	-3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	5	0	1	12	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	76	78	87
to Sell	71	63	53
Hld's(000)	39499	39588	39215

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.6	-5.8
3 yr.	49.6	27.9
5 yr.	75.5	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	21.60	22.75	Revenues per sh	24.50
3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	5.80	6.10	"Cash Flow" per sh	7.00
1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	2.05	2.20	Earnings per sh A	2.50
--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	1.23	1.23	Div'd Decl'd per sh B	1.50
1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	7.75	6.40	Cap'l Spending per sh	7.25
8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	25.90	26.80	Book Value per sh C	29.50
51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	40.55	40.65	Common Shs Outst'g D	41.00
10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	Bold figures are		Avg Ann'l P/E Ratio	17.0
.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.92	Value Line		Relative P/E Ratio	1.05
--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%	estimates		Avg Ann'l Div'd Yield	3.5%
						816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	849.9	875	925	Revenues ($mill)	1000
						61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	81.9	85.0	90.0	Net Profit ($mill)	100
						29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	29.9%	31.0%	31.0%	Income Tax Rate	31.0%
						8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	27.5%	24.0%	17.0%	AFUDC % to Net Profit	15.0%
						51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.7%	55.0%	55.5%	Long-Term Debt Ratio	57.0%
						48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.3%	45.0%	44.5%	Common Equity Ratio	43.0%
						1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2150.8	2335	2450	Total Capital ($mill)	2800
						1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2695.5	2860	2960	Net Plant ($mill)	3325
						6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.3%	5.0%	5.5%	Return on Total Cap'l	5.5%
						10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	8.0%	8.0%	Return on Shr. Equity	8.5%
						10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	8.0%	8.0%	Return on Com Equity E	8.5%
						10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.4%	3.5%	3.5%	Retained to Com Eq	3.0%
						--	--	--	--	--	26%	43%	47%	49%	57%	59%	58%	All Div'ds to Net Prof	61%

CAPITAL STRUCTURE as of 12/31/15
Total Debt $1276.0 mill. Due in 5 Yrs $270.0 mill.
LT Debt $1134.3 mill. LT Interest $68.2 mill.
(LT interest earned: 2.4x)

Pension Assets-12/15 $260.0 mill.
Oblig. $325.7 mill.
Pfd Stock None

Common Stock 40,443,817 shs.

MARKET CAP: $1.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.4	-1.6	+2.3
Avg. Indust. Use (MWH)	21908	21505	21687
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1852	1879	2055
Peak Load, Summer (Mw)	1750	1766	1794
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.3	+1.4
Fixed Charge Cov. (%)	280	251	218

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	3.5%	1.0%	2.0%
"Cash Flow"	6.5%	5.0%	3.5%
Earnings	12.0%	4.0%	2.5%
Dividends	--	--	5.0%
Book Value	8.0%	7.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	196.6	917.5
2015	163.8	219.5	289.7	176.9	849.9
2016	*170*	*235*	*290*	*180*	*875*
2017	*180*	*245*	*305*	*195*	*925*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.10	2.27
2015	.09	.52	1.40	.02	2.03
2016	*Nil*	*.65*	*1.25*	*.15*	*2.05*
2017	*.10*	*.65*	*1.30*	*.15*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016	.295				

BUSINESS: El Paso Electric Company (EPE) provides electric service to 405,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 47%; gas, 34%; coal, 6%; purchased, 13%. Fuel costs: 28% of revenues. '15 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Charles A. Yamarone. President & CEO: Mary Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company has reached a settlement of its rate case in Texas. The utility is trying to place units 1 and 2 of what will be a four-unit gas-fired generating station into the rate base, along with other capital expenditures since its last rate case. EPE had requested a $70.5 million tariff hike, based on a 10.1% return on a common-equity ratio of 49.52%. It reached a settlement with the city of El Paso that calls for a $37 million increase, an $8.5 million reduction in depreciation (based on lower depreciation rates), and the potential for an additional $8 million boost for costs associated with the EPE's stake in a coal-fired plant, which the company hopes to sell by July. However, there is no assurance that the Texas regulators will approve the settlement, especially since four intervenors oppose it. There is no time frame for the commission to put forth its ruling, but an interim rate increase took effect at the start of April.

A rate case is pending in New Mexico, as well. EPE is seeking a tariff hike of $6.4 million, based on a return of 9.95% on a common-equity ratio of 49.29%. A hearing examiner recommended a raise of just $640,000, based on a 9.6% ROE. An order is expected in June.

We think earnings will be relatively flat this year. In 2015, the effects of regulatory lag hurt the company. On the other hand, weather patterns were favorable for the company, especially in the third quarter. We have trimmed our 2016 estimate by a nickel a share, to $2.05, because the March period was probably weaker than we previously expected. Note that management has not put forth earnings guidance for 2016 because the aforementioned rate cases are pending.

We forecast higher profits in 2017. The company will benefit from a full year of rate relief it gets in 2016.

We think the board of directors will raise the dividend next month. This has been the pattern in recent years. We look for a $0.015-a-share (5.1%) hike in the quarterly disbursement, the same as in the past three years.

The dividend yield of this timely stock is on the low side for a utility. Total return potential to 2019-2021 is low, too.

Paul E. Debbas, CFA *April 29, 2016*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't add to full-year total due to rounding. Next earnings report due early May. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '15: $115.1 mill., $2.85/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '10: none specified; earned on average common equity, '15: 8.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	85

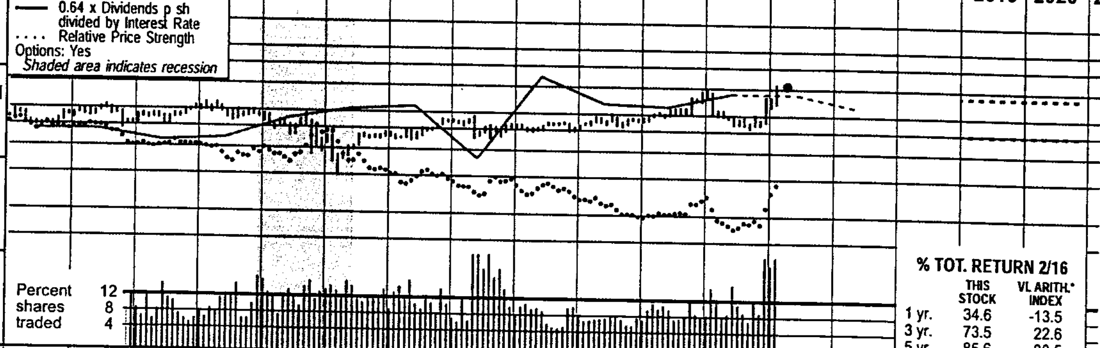
EMPIRE DISTRICT NYSE-EDE

RECENT PRICE 33.13 | P/E RATIO 25.5 (Trailing: 25.5 / Median: 16.0) | RELATIVE P/E RATIO 1.44 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS – Suspended 2/19/16
SAFETY 2 Raised 3/23/12
TECHNICAL – Suspended 2/19/16
BETA .70 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	25.0	25.1	26.1	23.5	19.4	22.5	23.3	22.0	24.3	31.2	31.5	33.7
Low:	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5	20.6	22.0	20.7	26.2

LEGENDS
—— 0.64 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2019 | 2020 | 2021

% TOT. RETURN 2/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.6	-13.5
3 yr.	73.5	22.6
5 yr.	85.6	38.5

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(-10%)	*1%*
Low	20	(-40%)	*-7%*

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	7
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	65	68	80
to Sell	65	49	58
Hld's(000)	20421	20727	21556

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.11	13.81	15.00	*13.75*	*14.40*	*15.10*	Revenues per sh	*16.75*
3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.99	3.14	3.45	*3.40*	*3.55*	*3.75*	"Cash Flow" per sh	*4.50*
1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.32	1.48	1.55	1.29	*1.35*	*1.40*	Earnings per sh A	*1.75*
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.01	1.03	1.04	*1.04*	*1.06*	Div'd Decl'd per sh B ■ †	*1.20*
7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.22	3.60	4.91	*4.05*	*2.85*	*2.65*	Cap'l Spending per sh	*3.25*
13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.90	17.43	18.02	*18.20*	*18.45*	*18.80*	Book Value per sh C	*19.75*
17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.48	43.04	43.48	*44.00*	*44.50*	*45.00*	Common Shs Outst'g D	*48.00*
17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	15.8	15.0	16.2	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	.99	1.01	.84	.85	.95	*Value Line*		Relative P/E Ratio	*.85*
5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	4.8%	4.5%	4.1%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $879.6 mill. Due in 5 Yrs $213.6 mill.
LT Debt $863.0 mill. LT Interest $43.9 mill.
Incl. $3.7 mill. capitalized leases.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/14 $192.7 mill. Oblig. $251.9 mill.

Pfd Stock None

Common Stock 43,787,249 shs. as of 10/30/15

MARKET CAP: $1.5 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
413.5	490.2	518.2	497.2	541.3	576.9	557.1	594.3	652.3	605.6	*640*	*680*	Revenues ($mill)	*800*
39.9	33.2	39.7	41.3	47.4	55.0	55.7	63.4	67.1	56.6	*60.0*	*65.0*	Net Profit ($mill)	*85.0*
35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	38.0%	37.1%	36.9%	*37.5%*	*38.0%*	*38.0%*	Income Tax Rate	*37.5%*
10.7%	23.1%	31.5%	34.2%	21.5%	.9%	3.5%	9.4%	14.8%	*14.0%*	*3.0%*	*3.0%*	AFUDC % to Net Profit	*5.0%*
49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	49.1%	49.8%	50.6%	*51.0%*	*53.5%*	*50.0%*	Long-Term Debt Ratio	*50.5%*
50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	50.9%	50.2%	49.4%	*49.0%*	*46.5%*	*50.0%*	Common Equity Ratio	*49.5%*
931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1409.4	1493.6	1586.5	*1640*	*1760*	*1695*	Total Capital ($mill)	*1900*
1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1657.6	1751.9	1910.3	*1995*	*2020*	*2035*	Net Plant ($mill)	*2175*
5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.4%	5.6%	5.5%	*4.5%*	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.0%*	*7.0%*	*7.5%*	Return on Shr. Equity	*9.0%*
8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.0%*	*7.0%*	*7.5%*	Return on Com Equity E	*9.0%*
.8%	NMF	NMF	NMF	NMF	4.1%	1.9%	2.7%	2.9%	*1.5%*	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
90%	117%	109%	109%	110%	49%	76%	68%	66%	*80%*	*78%*	*75%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-3.2	+1.3	+1.3
Avg. Industrial Use (MWH)	2913	2943	2981
Avg. Industrial Revs. per KWH (¢)	7.66	7.93	8.21
Capacity at Peak (Mw)	1391	1377	1326
Peak Load, Summer (Mw)	1142	1080	1162
Annual Load Factor (%)	52.2	56.2	52.8
% Change Customers (avg.)	+.6	+.5	+.3
Fixed Charge Cov. (%)	314	331	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	3.0%	3.0%	*5.0%*
Earnings	2.5%	5.0%	*2.5%*
Dividends	-2.5%	-4.5%	*2.5%*
Book Value	1.5%	2.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	151.1	136.6	157.5	149.1	594.3
2014	179.7	149.8	171.5	151.3	652.3
2015	164.5	134.6	169.7	136.8	605.6
2016	*180*	*145*	*170*	*145*	*640*
2017	*190*	*155*	*180*	*155*	*680*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.30	.27	.56	.35	1.48
2014	.48	.26	.55	.26	1.55
2015	.34	.15	.58	.23	1.29
2016	*.27*	*.24*	*.56*	*.28*	*1.35*
2017	*.26*	*.26*	*.58*	*.30*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.25	.25	.25	.25	1.00
2013	.25	.25	.25	.255	1.01
2014	.255	.255	.255	.26	1.03
2015	.26	.26	.26	.26	1.04
2016	.26				

BUSINESS: The Empire District Electric Company supplies electricity to 169,000 customers in a 10,000 sq. mi. area in southwestern Missouri (90% of retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (2%). Acquired Missouri Gas (44,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Elec. rev. breakdown: residential, 45%; commercial, 32%; industrial, 16%; other, 7%. Generating sources: coal, 47%; gas, 27%; hydro, 1%; purch., 25%. Fuel costs: 37% of revenues. '14 reported depr. rate: 3.0%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

Empire District Electric Company has accepted a takeover offer. This came as no surprise, given that the company had stated in December that it was in the early stages of exploring strategic alternatives. Algonquin, a Canadian company that owns electric, gas, and water utilities in the United States, has agreed to pay Empire District stockholders $34.00 in cash for each of their shares. The deal requires the approval of Empire District stockholders, the Federal Energy Regulatory Commission, and the regulators in Missouri, Kansas, Oklahoma, and Arkansas. The companies are targeting the first quarter of 2017 for completion of the acquisition.

We advise Empire District stockholders to sell their shares on the open market. The equity is trading at a discount of less than 5% to the buyout price. In our view, this upside potential is not enough to make it worthwhile for stockholders to assume downside risk if the deal falls through. Note that Empire District has already been involved in one unsuccessful takeover attempt as the acquiree, in 1999.

An electric rate case is pending in Missouri. The utility is seeking a $33.4 million (7.3%) tariff hike, based on a return of 9.9% on a common-equity ratio of 49%. Empire District wants to place a $165 million upgrade to a gas-fired generating unit in the rate base. It also wants to earn an adequate ROE; this figure was just 7.1% in 2015. The rate order should take effect in September.

Regulatory lag will continue to affect Empire District's earnings this year. The assets that the utility is building will be completed late in the first quarter or early in the second, several months before new tariffs take effect. Even so, considering that regulatory lag was also a problem in 2015, profits are likely to rise significantly. Mild weather in late 2015 also hurt the bottom line; we estimate normal weather in our estimates and projections. Our 2016 estimate of $1.35 a share *includes* costs (estimated at $0.10-$0.12 a share) associated with the takeover.

We forecast further profit growth in 2017. Empire District will benefit from a full year's effect of the rate order that is due in September.

Paul E. Debbas, CFA *March 18, 2016*

(A) Diluted earnings. Excl. loss from discontinued operations: '06, 2¢. '15 EPS don't add due to rounding. Next earnings report due early May. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan avail. (3% discount). † Shareholder investment plan avail. (C) Incl. intangibles. In '14: $5.93/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '15: none specified; earned on avg. com. eq., '14: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	80

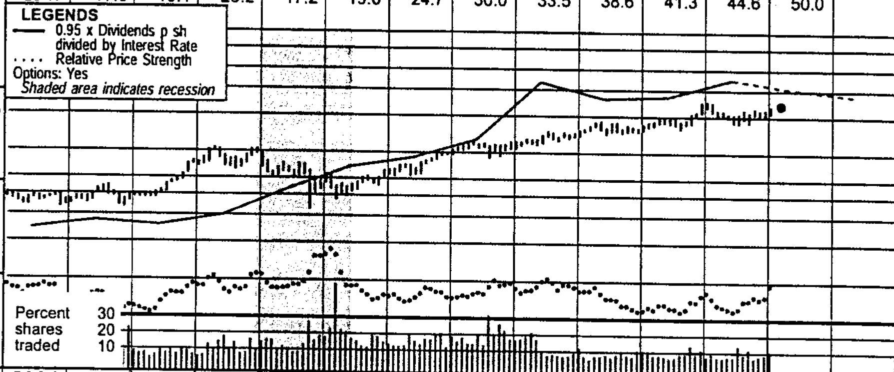
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 54.69 | P/E RATIO 19.1 (Trailing: 19.8; Median: 17.0) | RELATIVE P/E RATIO 1.19 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Lowered 8/14/15
SAFETY 1 Raised 5/22/15
TECHNICAL 3 Lowered 1/1/16
BETA .75 (1.00 = Market)

High:	22.0	28.9	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8	56.0
Low:	17.3	19.1	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6	50.0

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	6%
Low	50	(-10%)	2%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	0	0
to Sell	0	1	2	0	2	0	1	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	203	236	240
to Sell	255	206	198
Hld's(000)	223824	226206	222199

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.2	-10.4
3 yr.	46.5	20.6
5 yr.	93.9	40.9

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	*25.00*	*25.10*	*25.65*	Revenues per sh	*27.25*
3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	*5.10*	*5.45*	*5.85*	"Cash Flow" per sh	*7.00*
d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	*2.95*	*3.15*	Earnings per sh A	*3.75*
.40	.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	*1.78*	*1.90*	Div'd Decl'd per sh B ■	*2.20*
2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	*6.10*	*6.95*	*8.30*	Cap'l Spending per sh	*6.25*
15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	*32.50*	*33.60*	*34.80*	Book Value per sh C	*38.75*
143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	*318.00*	*319.00*	*320.00*	Common Shs Outst'g D	*323.00*
--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
--	.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.92	*Value Line*		Relative P/E Ratio	*.90*
1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $10002 mill. **Due in 5 Yrs** $3825.7 mill.
LT Debt $8757.5 mill. **LT Interest** $378.8 mill.
(LT interest earned: 4.6x)

Leases, Uncapitalized Annual rentals $20.1 mill.
Pension Assets-12/14 $4126.5 mill.
Oblig. $5486.2 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 317,191,249 shs.
as of 10/31/15
MARKET CAP: $17 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
6884.4	5822.2	5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	7954.8	*8000*	*8200*	Revenues ($mill)	*8800*
126.2	251.5	296.2	335.6	377.8	400.3	533.0	793.7	827.1	886.0	*950*	*1020*	Net Profit ($mill)	*1200*
--	30.3%	29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	37.9%	*37.5%*	*37.5%*	Income Tax Rate	*37.5%*
21.5%	13.9%	15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	*4.0%*	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
58.7%	59.2%	60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	*46.5%*	*46.5%*	*46.5%*	Long-Term Debt Ratio	*47.0%*
39.7%	39.2%	38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	*53.0%*	*52.5%*	*52.5%*	Common Equity Ratio	*53.5%*
7052.0	7431.1	7926.2	8629.5	8741.8	8856.0	16675	17544	18738	*19550*	*20325*	*21200*	Total Capital ($mill)	*23800*
6242.2	7229.9	8207.9	8840.0	9567.7	10403	16605	17576	18647	*19975*	*21550*	*23500*	Net Plant ($mill)	*27300*
2.9%	5.0%	5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	*5.5%*	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
4.3%	8.3%	9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	*8.5%*	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	*8.5%*	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
.3%	4.3%	5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	*3.5%*	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
94%	50%	45%	50%	49%	50%	72%	59%	58%	*61%*	*61%*	*60%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+47.0	+1.0	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+59.8	NA	NA
Fixed Charge Cov. (%)	320	427	426

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	-7.0%	-8.5%	*3.0%*
"Cash Flow"	-2.0%	-3.0%	*6.0%*
Earnings	8.0%	5.5%	*7.0%*
Dividends	9.5%	11.5%	*6.0%*
Book Value	5.5%	9.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1995	1635	1892	1777	7301.2
2014	2290	1677	1892	1881	7741.9
2015	2513	1817	1933	1691	7954.8
2016	*2400*	*1800*	*1950*	*1850*	*8000*
2017	*2450*	*1850*	*2000*	*1900*	*8200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.72	.54	.66	.56	2.49
2014	.74	.40	.74	.69	2.58
2015	.80	.65	.74	.57	2.76
2016	*.85*	*.65*	*.80*	*.65*	*2.95*
2017	*.90*	*.70*	*.85*	*.70*	*3.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.294	.343	.343	.343	1.32
2013	.3675	.3675	.3675	.3675	1.47
2014	.3925	.3925	.3925	.3925	1.57
2015	.4175	.4175	.4175	.4175	1.67
2016	.445				

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 million electric, 504,000 gas customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to three fourths of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts. Acquired NSTAR 4/12. Electric revenue breakdown: residential, 49%; commercial, 38%; industrial, 5%; other, 8%. Fuel costs: 39% of revenues. '14 reported deprec. rates: 2.7%-3.3%. Has 8,200 employees. Chairman, President & CEO: Thomas J. May. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

We estimate that Eversource Energy's earnings will climb 7% in 2016 and 2017. At the start of the new year, a $15.8 million gas rate increase took effect in Massachusetts. Eversource is also benefiting from investment in its transmission system. Despite a reduction in its allowed return on equity for transmission, to about 11.5%, this figure is still well above the utility's allowed ROE for distribution. Eversource expects to spend $3.9 billion over the next four years. Customer conversions from oil heat to gas heat are another advantage. Finally, Eversource continues to reduce operating and maintenance expenses stemming from the merger that formed the company in 2012. Our 2016 earnings estimate is within management's targeted range of $2.90-$3.05 a share. Note that Eversource has trimmed its annual earnings growth goal from 6%-8% to 5%-7% due to the effects of bonus depreciation, which at least will provide cash benefits totaling $850 million-$900 million this year and next.

The board of directors raised the dividend. As we had estimated, the increase was $0.11 a share (6.6%) annually.

Some large capital projects are in various stages of development. Eversource is seeking regulatory approval to build a $1.6 billion transmission line to Quebec. Construction would begin by early 2017, with an in-service date in the first half of 2019. The company has a 40% stake ($1.2 billion) in a proposed pipeline to bring gas to New England. An application with the Federal Energy Regulatory Commission will be made this year, with a targeted in-service date in 2018. Finally, the company is making a bid to build a transmission line in Massachusetts. This would be an investment of more than $400 million.

Eversource is still awaiting a regulatory ruling on its proposed sale of its generating assets in New Hampshire. The assets contribute $0.09-$0.10 to the bottom line annually. The company would expect to recover its $700 million investment by early 2017. A decision is likely next month.

This high-quality stock has a modest dividend yield, by utility standards. Total return potential to 2019-2021 is also lackluster.

Paul E. Debbas, CFA *February 19, 2016*

(A) Dil. EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '13 & '14 EPS don't add due to rounding. Next earnings report due early May.
(B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '14: $23.89/sh. (D) In mill. (E) Rate all'd on com. eq. in MA: (elec) '11, 9.6%; (gas) '16, 9.8%; in CT: (elec.) '15, 9.02%; (gas) '15, 9.5%; in NH: '10, 9.67%; earn. on avg. com. eq., '14: 8.4%. Regul. Clim.: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	85

GREAT PLAINS EN'GY NYSE-GXP

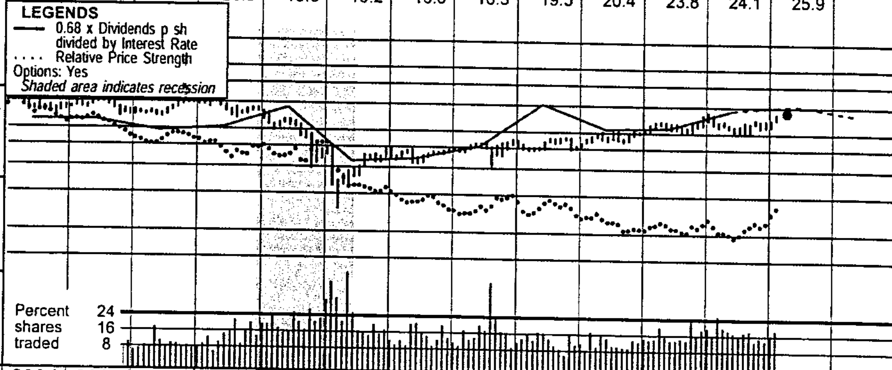
RECENT PRICE	30.28	P/E RATIO	17.3 (Trailing: 22.1 / Median: 16.0)	RELATIVE P/E RATIO	0.98	DIV'D YLD	3.6%	VALUE LINE

TIMELINESS 2 Raised 3/4/16
SAFETY 3 Lowered 12/26/08
TECHNICAL 2 Raised 3/18/16
BETA .80 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:					32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3	30.3	
Low:					27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1	25.9	

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 0.68 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+15%)	8%
Low	25	(-15%)	Nil

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	4	0	0	2	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	122	108	113
to Sell	125	134	117
Hld's(000)	130044	125340	123580

% TOT. RETURN 2/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.5	-13.5
3 yr.	50.3	22.6
5 yr.	85.8	38.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	16.21	*17.45*	*18.05*	Revenues per sh	*20.50*
4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	3.98	*4.70*	*5.10*	"Cash Flow" per sh	*6.50*
2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	1.37	*1.75*	*1.85*	Earnings per sh A	*2.00*
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	1.00	*1.06*	*1.12*	Div'd Decl'd per sh B ■	*1.30*
6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	4.42	*4.45*	*3.80*	Cap'l Spending per sh	*4.25*
14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	23.68	*24.40*	*25.10*	Book Value per sh C	*27.50*
61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	154.40	*154.75*	*155.00*	Common Shs Outst'g D	*155.75*
12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	19.4	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87	.98	*Value Line*		Relative P/E Ratio	*.90*
6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*
						2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	2502.2	*2700*	*2800*	Revenues ($mill)	*3200*
						127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	213.0	*275*	*290*	Net Profit ($mill)	*335*
						27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	36.7%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
						8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	4.5%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	50.3%	*47.0%*	*46.5%*	Long-Term Debt Ratio	*44.0%*
						67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	49.1%	*52.5%*	*53.0%*	Common Equity Ratio	*55.5%*
						1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	7440.6	*7175*	*7345*	Total Capital ($mill)	*7675*
						3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	8662.4	*8900*	*8985*	Net Plant ($mill)	*8925*
						7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	4.2%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
						9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	5.8%	*7.0%*	*7.5%*	Return on Shr. Equity	*7.5%*
						9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	5.8%	*7.5%*	*7.5%*	Return on Com Equity E	*7.5%*
						NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	1.6%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						104%	91%	NMF	81%	54%	66%	63%	55%	60%	73%	*60%*	*60%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $4155.2 mill. **Due in 5 Yrs** $1545.5 mill.
LT Debt $3745.1 mill. **LT Interest** $188.0 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $12.3 mill.
Pension Assets-12/15 $723.9 mill.
Oblig. $1154.8 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 154,414,902 shs.
as of 2/23/16
MARKET CAP: $4.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.2	+.4	-1.9
Avg. Indust. Use (MWH)	1424	1455	1450
Avg. Indust. Revs. per KWH (¢)	6.80	6.79	6.96
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.7	+.9	+.9
Fixed Charge Cov. (%)	267	261	254

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-7.0%	1.5%	*4.0%*
"Cash Flow"	-1.5%	2.5%	*8.5%*
Earnings	-4.0%	4.0%	*4.5%*
Dividends	-5.5%	-3.0%	*5.5%*
Book Value	4.5%	2.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	542.2	600.3	765.0	538.8	2446.3
2014	585.1	648.4	782.5	552.2	2568.2
2015	549.1	609.0	781.4	562.7	2502.2
2016	*600*	*650*	*850*	*600*	*2700*
2017	*625*	*675*	*875*	*625*	*2800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.17	.41	.93	.11	1.62
2014	.15	.34	.95	.12	1.57
2015	.12	.28	.82	.15	1.37
2016	*.20*	*.40*	*1.00*	*.15*	*1.75*
2017	*.20*	*.45*	*1.05*	*.15*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.2125	.2125	.2125	.2175	.86
2013	.2175	.2175	.2175	.23	.88
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245	.2625	1.00
2016	.2625				

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 846,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 9%; other, 12%. Generating sources: coal, 63%; nuclear, 13%; wind, 1%; gas & oil, 1%; purchased, 22%. Fuel costs: 24% of revs. '15 reported deprec. rate (utility): 3.0%. Has 2,900 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

Great Plains Energy's earnings will probably rise significantly this year. In the fall of 2015, the company's largest utility subsidiary, Kansas City Power & Light, was granted rate increases in Missouri and Kansas totaling $138.4 million. However, this didn't help earnings much last year because the fourth quarter is seasonally weak. With the tariff hikes in place for all of 2016, profits should advance materially. Our estimate is within Great Plains' targeted range of $1.65-$1.80 a share.

The company's Greater Missouri Operations have filed a rate case, and another application will come later this year. The utility is seeking an increase of $59.3 million (8.2%), based on a return of 9.9% on a common-equity ratio of 54.83%. New tariffs will take effect in early 2017. KCP&L will file an abbreviated case in Kansas by November, for a true-up of the cost of an environmental upgrade to a coal-fired facility. The utility might also file an application in Missouri in the second half of 2016.

Frequent rate filings are nothing new for these utilities. Due to the effects of regulatory lag, earned returns on equity have been low for the past several years. One reason is that Missouri has been resistant to granting regulatory mechanisms that track certain kinds of spending and provide some immediate rate relief for utilities. This might change, based on pending legislation there, but previous legislative efforts have been fruitless.

We forecast a moderate profit increase in 2017. Great Plains should benefit from additional rate relief, assuming reasonable regulatory treatment in this year's cases. The company has established a goal of 4%-5% annual earnings growth from 2017 through 2020. Great Plains' dividend growth target (beginning in 2016) is slightly higher, at 5%-7% a year, with a goal of 60%-70% for its payout ratio.

This timely stock has a dividend yield that is close to the electric utility average. Like most utility issues, the recent quotation is well within our 2019-2021 Target Price Range, so total return potential over that time frame is unattractive.

Paul E. Debbas, CFA *March 18, 2016*

(A) Diluted earnings. Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '14 earnings don't add due to rounding. Next earnings report due early May. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '15: $7.44/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in MO in '15: 9.5%; in KS in '15: 9.3%; earned on avg. com. eq., '15: 5.8%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	70

IDACORP, INC. NYSE-IDA

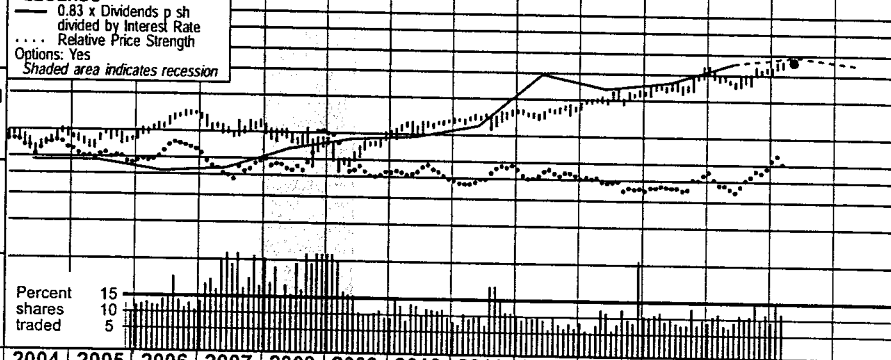
RECENT PRICE	74.00	P/E RATIO	18.8 (Trailing: 19.1 / Median: 14.0)	RELATIVE P/E RATIO	0.99	DIV'D YLD	2.9%	VALUE LINE

TIMELINESS 2 Raised 3/11/16
SAFETY 2 Raised 8/2/13
TECHNICAL 2 Raised 3/25/16
BETA .80 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5	75.0
Low:	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4	65.0

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 0.83 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(Nil)	4%
Low	55	(-25%)	-3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	10
to Sell	1	1	0	1	1	1	1	1	3

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	101	106	97
to Sell	100	95	101
Hld's(000)	37671	67529	39221

Percent shares traded 15 10 5

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.3	-5.8
3 yr.	69.4	27.9
5 yr.	128.7	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	*25.40*	*25.75*	Revenues per sh	*27.25*
5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	*6.85*	*7.15*	"Cash Flow" per sh	*8.00*
3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	*3.90*	*4.05*	Earnings per sh A	*4.50*
1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	*2.08*	*2.24*	Div'd Decl'd per sh B ■ †	*2.70*
3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	*6.15*	*5.65*	Cap'l Spending per sh	*6.25*
21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	*42.65*	*44.45*	Book Value per sh C	*49.75*
37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	*50.40*	*50.45*	Common Shs Outst'g D	*50.60*
10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	*Value Line*		Relative P/E Ratio	*.90*
4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $1746.5 mill. Due in 5 Yrs $352.1 mill.
LT Debt $1725.4 mill. LT Interest $82.5 mill.
(LT interest earned: 3.5x)

Pension Assets-12/15 $559.6 mill.
Oblig. $835.5 mill.

Pfd Stock None

Common Stock 50,297,581 shs.
as of 2/12/16

MARKET CAP: $3.7 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	1270.3	*1280*	*1300*	Revenues ($mill)	*1375*
100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	193.5	194.7	*195*	*205*	Net Profit ($mill)	*225*
13.3%	14.3%	16.3%	15.2%	--	--	13.4%	28.3%	8.0%	19.0%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
4.0%	9.7%	10.2%	10.5%	19.1%	23.3%	20.3%	12.3%	13.6%	16.3%	*16.0%*	*16.0%*	AFUDC % to Net Profit	*14.0%*
45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	45.6%	*46.0%*	*46.5%*	Long-Term Debt Ratio	*47.0%*
54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	54.4%	*54.0%*	*53.5%*	Common Equity Ratio	*53.0%*
2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	3783.3	*3995*	*4190*	Total Capital ($mill)	*4750*
2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	3992.4	*4155*	*4280*	Net Plant ($mill)	*4675*
6.2%	4.7%	5.3%	5.7%	6.0%	6.8%	6.5%	6.4%	6.6%	6.2%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	4.8%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
51%	64%	55%	46%	41%	36%	41%	43%	46%	50%	*53%*	*55%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+3.8	-3.6	+1.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.21	5.68	5.70
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3407	3184	3402
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	+1.4	+1.8
Fixed Charge Cov. (%)	329	287	307

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	2.0%	3.5%	*1.5%*
"Cash Flow"	5.5%	6.0%	*3.5%*
Earnings	9.5%	8.0%	*3.0%*
Dividends	2.5%	8.0%	*7.5%*
Book Value	5.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	264.9	303.9	381.1	296.2	1246.2
2014	292.7	317.8	382.2	289.8	1282.5
2015	279.4	336.3	369.2	285.4	1270.3
2016	*285*	*335*	*375*	*285*	*1280*
2017	*290*	*340*	*380*	*290*	*1300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.69	3.85
2015	.47	1.31	1.46	.63	3.87
2016	*.50*	*1.15*	*1.65*	*.60*	*3.90*
2017	*.55*	*1.15*	*1.70*	*.65*	*4.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.33	.33	.33	.38	1.37
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016	.51				

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 525,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 40%; commercial, 24%; industrial, 14%; irrigation, 13%; other, 9%. Generating sources: hydro, 36%; coal, 28%; gas, 13%; purchased, 23%. Fuel costs: 34% of revenues. '15 reported depreciation rate: 2.7%. Has 2,000 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

We estimate that IDACORP's earnings in 2016 will wind up just slightly above last year's tally. In 2015, the company recorded a $7 million tax benefit. We assume a higher tax rate this year. Our earnings estimate is within the company's targeted range of $3.80-$3.95 a share. Note that IDACORP was scheduled to report first-quarter earnings shortly after this report went to press.

We forecast respectable earnings growth in 2017. Idaho Power is benefiting from the strong economy in the utility's service area. The Electric Operating Statistics box shows that annual customer growth has exceeded 1% in recent years. Load growth isn't rising as fast as customer growth due to the effects of energy efficiency, but the utility still expects an increase of 1.2%-1.4% annually, a pace that is enviable for most electric companies today. Our profit estimate of $4.05 a share would produce a 4% increase.

IDACORP has a regulatory mechanism that will help protect its earnings through 2019. The company has $45 million of accumulated deferred investment tax credits that it may amortize into income if Idaho Power's return on equity in its Idaho jurisdiction would otherwise fall below 9.5%. The utility expects to utilize less than $5 million of these credits this year, but it is an ace in the hole that it has if its service area has an unusually mild summer.

We have raised the company's Financial Strength rating from B++ to A. Cash flow is solid. IDACORP is using open-market purchases for its dividend reinvestment program. The company has three million common shares available for issuance under its continuous equity plan, but expects no issuances this year. The fixed-charge coverage and common-equity ratio are sound.

This timely stock has a high valuation for a utility. The dividend yield is below the industry average, and the recent quotation is near the upper end of our 3- to 5-year Target Price Range. Some mid-cap utilities have become takeover targets, and we think some such speculation is reflected in the price of IDACORP stock. We do not advise investors to purchase this equity in the hope of a buyout offer, however.

Paul E. Debbas, CFA *April 29, 2016*

(A) Diluted EPS. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. '14 earnings don't add due to rounding. Next earnings report due late July. (B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '15: $26.16/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in '11: 10% (imputed); earned on avg. com. eq., '15: 9.7%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	95

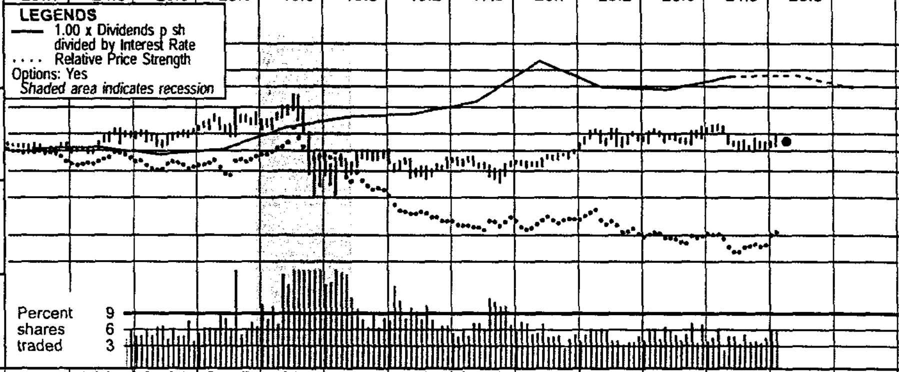
OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE	27.82	P/E RATIO	17.8 (Trailing: 17.8; Median: 23.0)	RELATIVE P/E RATIO	1.01	DIV'D YLD	4.5%	VALUE LINE

TIMELINESS 3 Raised 1/29/16
SAFETY 3 Lowered 12/24/10
TECHNICAL 3 Raised 3/18/16
BETA .85 (1.00 = Market)

High:	32.0	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4	29.4			
Low:	24.0	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8	25.8			

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+60%)	*16%*
Low	30	(+10%)	*6%*

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	49	53	46
to Sell	53	50	51
Hld's(000)	12614	12771	12314

% TOT. RETURN 2/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.5	-13.5
3 yr.	7.5	22.6
5 yr.	53.3	38.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	*21.30*	*21.40*	Revenues per sh	*27.40*
3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	*3.30*	*3.45*	"Cash Flow" per sh	*4.30*
1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	*1.60*	*1.65*	Earnings per sh A	*2.10*
1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	*1.25*	*1.27*	Div'd Decl'd per sh B ■	*1.33*
1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	*4.60*	*4.55*	Cap'l Spending per sh	*3.75*
10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	*17.10*	*17.95*	Book Value per sh C	*20.25*
23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	*38.00*	*39.00*	Common Shs Outst'g D	*42.00*
13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	18.2	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.88	.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	.92	*Value Line*		Relative P/E Ratio	*1.15*
4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $579.2 mill. Due in 5 Yrs $167.0 mill.
LT Debt $445.9 mill. LT Interest $30.0 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/15 $233.6 mill. Oblig. $302.7 mill.
Pfd Stock None

Common Stock 38,002,593 shs.
as of 2/12/16
MARKET CAP: $1.1 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
1105.0	1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	779.8	*810*	*835*	Revenues ($mill)	*1150*
50.8	54.0	35.1	26.0	13.6	16.4	39.0	50.2	56.9	58.6	*60.0*	*65.0*	Net Profit ($mill)	*90.0*
34.8%	34.1%	30.0%	--	--	14.5%	5.2%	21.3%	22.5%	27.0%	*25.0%*	*25.0%*	Income Tax Rate	*30.0%*
1.9%	4.2%	6.1%	4.0%	.6%	3.8%	1.7%	--	1.7%	3.6%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
33.5%	38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	42.4%	*42.5%*	*43.5%*	Long-Term Debt Ratio	*44.5%*
64.5%	59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	*57.5%*	*56.5%*	Common Equity Ratio	*55.5%*
763.0	882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	1051.0	*1130*	*1240*	Total Capital ($mill)	*1525*
718.6	854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	1387.8	*1500*	*1600*	Net Plant ($mill)	*1900*
7.7%	7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	6.7%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
10.0%	10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	9.7%	*9.0%*	*9.5%*	Return on Shr. Equity E	*10.5%*
10.2%	10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	*9.0%*	*9.5%*	Return on Com Equity	*10.5%*
3.3%	3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	2.0%	*2.0%*	*2.0%*	Retained to Com Eq	*4.0%*
68%	66%	108%	NMF	NMF	NMF	113%	87%	78%	79%	*80%*	*77%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+5.8	+4.6	-2.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	359	336	350

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-3.5%	-7.0%	*3.5%*
"Cash Flow"	-.5%	2.5%	*5.5%*
Earnings	-.5%	15.5%	*6.0%*
Dividends	1.0%	.5%	*1.5%*
Book Value	.5%	-3.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	218.0	212.4	229.8	233.1	893.3
2014	215.0	194.4	196.5	193.4	799.3
2015	202.8	188.2	200.0	188.8	779.8
2016	*210*	*195*	*205*	*200*	*810*
2017	*215*	*200*	*210*	*210*	*835*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.41	.21	.41	.35	1.37
2014	.59	.27	.43	.28	1.55
2015	.37	.36	.42	.41	1.56
2016	*.40*	*.30*	*.45*	*.45*	*1.60*
2017	*.42*	*.30*	*.46*	*.47*	*1.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.298	.298	.298	.298	1.19
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308	.308	1.23
2016	.313				

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (50% of retail elec. revs.), North Dakota (41%); and South Dakota (9%). Electric rev. breakdown, '15: residential, 32%; commercial & farms, 35%; industrial, 30%; other, 3%. Fuel costs: 15.5% of revenues. Also has operations in manufacturing and plastics. 2015 depr. rate: 2.9%. Has 2,005 employees. Off. and dir. own 1.6% of common stock; Cascade Investment, LLC, 9.1%; The Vanguard Group, 7.1%; BlackRock, Inc., 5.4% (2/15 Proxy). CEO: Charles MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 866-410-8780. Internet: www.ottertail.com.

Otter Tail reported mixed results for the fourth quarter. The top line declined modestly due to lower revenue in the electric utility and manufacturing businesses. Performance at the utility was hurt by relatively warm weather, while the manufacturing segment's operating environment remained challenging. On the bright side, earnings increased thanks to lower expenses. Strong project management and the related regulatory recovery of the utility's investments in environmental upgrades and transmission lines contributed to bottom-line growth.

The board of directors has increased the dividend modestly. Beginning with the March payout, the quarterly dividend is now $0.3125 per share. Annual dividend growth will probably continue.

Otter Tail Power has filed a rate case in Minnesota. It has asked the Minnesota Public Utilities Commission for permission to increase its rates. The company cited rising costs as well as investments in technology and infrastructure as reasons for the proposed increase. A final determination is expected next year. In the meantime, the utility is seeking an interim increase, which would take effect in mid-April of this year.

Growth may well remain muted in the near term. Challenging business conditions should continue to hinder the performance of the manufacturing segment. The electric business ought to perform fairly well, though. Investments in two large transmission projects in 2016 will likely boost earnings here.

Long-term prospects appear somewhat more favorable. The company's recently completed strategic transformation has allowed it to reduce risk and improve growth opportunities. Solid results from the electric line should remain the primary driver of performance here, and we also envision healthy improvement from the manufacturing business. Growth will likely pick up as the end of the decade approaches.

These shares may be suitable for income-minded, buy-and-hold accounts. Indeed, the dividend yield is above average. From the recent quotation, this equity offers decent long-term total return potential.

Michael Napoli, CFA *March 18, 2016*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢. Earnings may not sum due to rounding. Next earnings report due in May.
(B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '15: $55.4 mill., $1.46/sh. (D) In mill.
(E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	15
Earnings Predictability	50

PINNACLE WEST NYSE-PNW

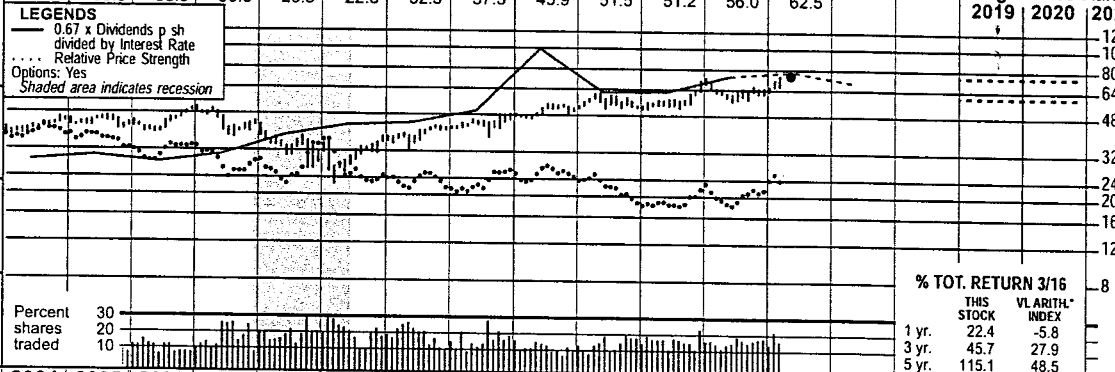
RECENT PRICE 74.85 | P/E RATIO 18.6 (Trailing: 19.1 Median: 15.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 1 Raised 4/1/16
SAFETY 1 Raised 5/3/13
TECHNICAL 3 Lowered 4/1/16
BETA .75 (1.00 = Market)

High:	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3	75.8	
Low:	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0	62.5	

LEGENDS
— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(Nil)	4%
Low	60	(-20%)	-1%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	13	0	0	1	14
to Sell	1	0	0	0	0	1	1	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	175	181	196
to Sell	180	175	167
Hld's(000)	87394	89339	88855

Percent shares traded 30 20 10

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.4	-5.8
3 yr.	45.7	27.9
5 yr.	115.1	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	*32.75*	*33.95*	Revenues per sh	*38.25*
7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	*9.35*	*9.85*	"Cash Flow" per sh	*11.25*
3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	*4.00*	*4.25*	Earnings per sh A	*4.75*
1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	*2.56*	*2.68*	Div'd Decl'd per sh B ■	*3.10*
7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	*11.25*	*11.95*	Cap'l Spending per sh	*10.25*
28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	*42.70*	*44.25*	Book Value per sh C	*48.75*
84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	*111.50*	*112.00*	Common Shs Outst'g D	*113.50*
11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.5*
.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	*estimates*		Relative P/E Ratio	*.90*
3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%			Avg Ann'l Div'd Yield	*4.5%*

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	*3650*	*3800*	Revenues ($mill)	*4350*
317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	437.3	*445*	*475*	Net Profit ($mill)	*540*
33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	*34.5%*	*34.5%*	Income Tax Rate	*34.5%*
11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	*11.0%*	*12.0%*	AFUDC % to Net Profit	*8.0%*
48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	*45.5%*	*46.0%*	Long-Term Debt Ratio	*45.0%*
51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	*54.5%*	*54.0%*	Common Equity Ratio	*55.0%*
6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	*8750*	*9190*	Total Capital ($mill)	*10075*
7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	11809	*12475*	*13175*	Net Plant ($mill)	*14550*
6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	*9.5%*	*9.5%*	Return on Com Equity E	*10.0%*
3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
63%	70%	96%	89%	66%	68%	58%	58%	62%	59%	*64%*	*63%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $3820.0 mill. **Due in 5 Yrs** $1314.6 mill.
LT Debt $3462.4 mill. **LT Interest** $169.7 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 5.0x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/15 $2542.8 mill. Oblig. $3033.8 mill.
Pfd Stock None

Common Stock 111,004,916 shs. as of 2/12/16
MARKET CAP: $8.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	-.2	-1.8	+1.3
Avg. Indust. Use (MWH)	644	659	658
Avg. Indust. Revs. per KWH (¢)	8.21	8.26	8.17
Capacity at Peak (Mw)	8398	9259	9250
Peak Load, Summer (Mw)	6927	7007	7031
Annual Load Factor (%)	50.0	48.6	48.3
% Change Customers (yr-end)	+1.4	+1.2	+1.3
Fixed Charge Cov. (%)	419	404	438

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	--	-.5%	3.5%
"Cash Flow"	2.5%	2.0%	5.0%
Earnings	4.5%	8.5%	4.0%
Dividends	2.5%	2.0%	5.0%
Book Value	2.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	890.7	1199.1	734.4	3495.4
2016	*700*	*975*	*1225*	*750*	*3650*
2017	*725*	*1025*	*1275*	*775*	*3800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	.05	3.58
2015	.14	1.10	2.30	.37	3.92
2016	*Nil*	*1.30*	*2.35*	*.35*	*4.00*
2017	*.15*	*1.35*	*2.40*	*.35*	*4.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.525	.525	.525	.545	2.12
2013	.545	.545	.545	.567	2.20
2014	.568	.568	.568	.595	2.30
2015	.595	.595	.595	.625	2.41
2016	.625				

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 49%; commercial, 39%; industrial, 5%; other, 7%. Generating sources: coal, 31%; nuclear, 27%; gas & other, 20%; purchased, 22%. Fuel costs: 32% of revenues. '15 reported deprec. rate: 2.7%. Has 6,400 employees. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary is planning to file a rate case. Arizona Public Service has given the Arizona Corporation Commission (ACC) notice of its intent to file a case on June 1st. What will be noteworthy won't be the utility's revenue requirement, but other aspects of the case. Residential rate design will be a key issue. About 70% of the utility's costs of serving residential customers are fixed, but only 10% of revenues come from fixed charges on customers' bills. Another problem is the subsidization of rooftop solar users by nonsolar customers. The ACC has been conducting hearings about the difficulties that utilities in the state (not just APS) are facing. APS also plans to ask for a decoupling mechanism so that revenues are based on customer growth, not volume growth. This would replace a regulatory mechanism that provides the utility with only partial compensation for the effects of energy efficiency on volume. APS will also ask the ACC to allow it to defer (for future recovery) costs associated with two major construction projects (see below). The company is asking for new rates to take effect in mid-2017.

We estimate a modest earnings increase in 2016. APS benefits from regulatory mechanisms that provide annual revenues for certain kinds of spending, such as for electric transmission. However, a major overhaul at a coal-fired unit will hurt the March-quarter earnings comparison. Our estimate is at the midpoint of management's targeted range of $3.90-$4.10 a share. Without the costs of this overhaul in 2017, profit growth should be greater next year. Our estimate is $4.25 a share.

The utility expects to start construction on two major capital projects in 2016. APS is building a 510-megawatt gas-fired plant that will replace 290 mw of old capacity. The expected cost is $500 million. An environmental upgrade to two coal-fired units is expected to cost $400 million.

This stock is ranked 1 (Highest) for both Timeliness and Safety. The dividend yield is only about average for a utility, and with the recent quotation near the upper end of our 2019-2021 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *April 29, 2016*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '15 EPS don't add due to rounding. Next earnings report due late July. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred chgs. In '15: $13.77/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '15: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	75

PNM RESOURCES NYSE-PNM | RECENT PRICE 32.48 | P/E RATIO 20.4 (Trailing: NMF / Median: 17.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS **3** Lowered 6/19/15

SAFETY **3** Lowered 5/9/08

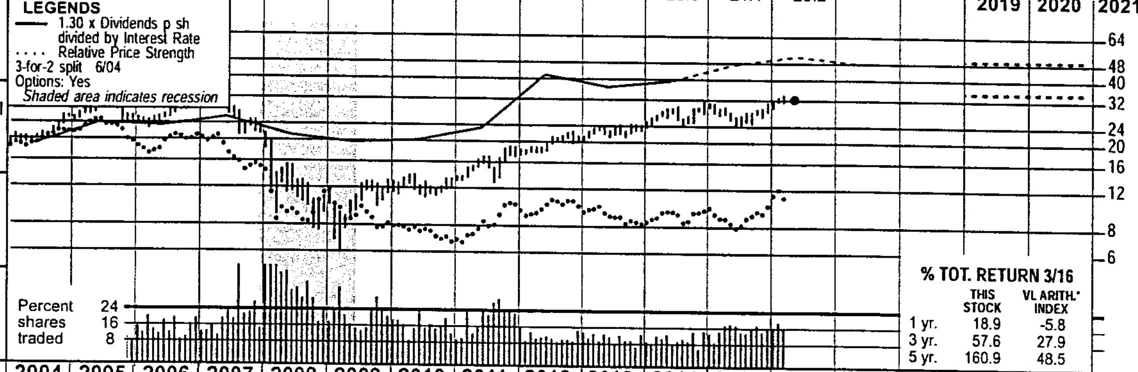
TECHNICAL **1** Raised 4/22/16

BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2	34.1
Low:	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4	29.2

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 6/04
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+55%)	14%
Low	35	(+10%)	6%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	1	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	3	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	116	99	112
to Sell	104	108	85
Hld's(000)	69968	71254	72521

Percent shares traded 24 16 8

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.9	-5.8
3 yr.	57.6	27.9
5 yr.	160.9	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	18.75	20.40	Revenues per sh	20.30
3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.62	3.70	3.85	4.10	"Cash Flow" per sh	4.70
1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.64	1.60	1.85	Earnings per sh A	2.35
.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.80	.88	.96	Div'd Decl'd per sh B ■†	1.30
2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	5.50	5.60	5.65	Cap'l Spending per sh	5.50
15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.76	22.70	23.60	Book Value per sh C	25.50
58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	80.00	80.00	Common Shs Outst'g D	80.00
8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	16.9	Bold figures are		Avg Ann'l P/E Ratio	16.0
.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.86	Value Line		Relative P/E Ratio	1.00
4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	2.9%	estimates		Avg Ann'l Div'd Yield	3.5%
						2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	1500	1630	Revenues ($mill)	1625
						122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	116.3	131.5	135	150	Net Profit ($mill)	190
						24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	35.0%	35.0%	35.0%	Income Tax Rate	35.0%
						4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	1.3%	1.5%	2.5%	3.0%	AFUDC % to Net Profit	8.0%
						50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	54.3%	53.0%	53.5%	Long-Term Debt Ratio	52.5%
						48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	45.6%	46.0%	45.5%	Common Equity Ratio	46.5%
						3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	3624.3	3845	4025	Total Capital ($mill)	4385
						3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4535.4	4655	4800	Net Plant ($mill)	5270
						4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	5.1%	5.0%	5.0%	5.5%	Return on Total Cap'l	6.0%
						7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.9%	7.5%	8.0%	Return on Shr. Equity	9.5%
						7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.9%	7.5%	8.0%	Return on Com Equity E	9.5%
						3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.2%	4.0%	3.5%	3.5%	Retained to Com Eq	3.5%
						49%	117%	NMF	86%	58%	47%	43%	45%	51%	49%	51%	52%	All Div'ds to Net Prof	55%

CAPITAL STRUCTURE as of 12/31/15
Total Debt $2342.6 mill. Due in 5 Yrs $1054 mill.
LT Debt $1967.0 mill. LT Interest $110 mill.
(LT interest earned: 2.4x)
Pension Assets-12/15 $620.0 mill. Oblig. $662.1 mill.

Pfd Stock $11.5 mill. Pfd Div'd $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 2/19/16
MARKET CAP: $2.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS F

	2013	2014	2015
% Change Retail Sales (KWH)	-2.9	-2.1	+2.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2572	2707	2787
Peak Load, Summer (Mw)	2008	1948	1889
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.7	+.6	+.9
Fixed Charge Cov. (%)	241	250	N/A

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	-3.0%	-4.5%	1.5%
"Cash Flow"	1.5%	9.5%	5.0%
Earnings	1.5%	23.5%	9.0%
Dividends	1.0%	--	10.0%
Book Value	2.0%	1.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	352.9	417.4	335.9	1439.1
2016	345	360	440	355	1500
2017	375	390	475	390	1630

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.18	.38	.64	.21	1.41
2014	.16	.36	.69	.24	1.45
2015	.21	.44	.76	.23	1.64
2016	.22	.40	.74	.24	1.60
2017	.28	.46	.81	.30	1.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.145	.145	.145	.145	.58
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22				

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP), which generate, transmit, and distribute electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '15: residential, 30%; commercial, 32%; industrial, 19%; other, 19%. Fuels: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 49% of revenues. '15 depreciation rate: 3.3%. Has 1,881 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

We've trimmed a nickel off our 2016 share-net estimate for PNM Resources. Our revised target of $1.60 represents a 2% decline from the adjusted $1.64 earned last year by the electric-utility holding company. Previously, we thought results would be roughly flat on a year-over-year basis.

The downward revision is to better reflect, in part, somewhat challenging conditions within the utility's service area. Public Service of New Mexico (PSNM) doesn't directly serve regions of the state that produce oil and gas. Still, management recently conceded that energy-sector layoffs and a decrease in state royalty revenues would hurt certain local economies within the power provider's operating territory.

Near-term regulatory concerns have also bubbled up. Notably, the New Mexico Public Regulation Commission is said to have issued a temporary halt on a $123.5 million rate case that PSNM filed last year. The new rates will now reportedly go into effect in August, at the earliest. The delay could reduce share net by $0.08 or more.

Earnings should rebound next year. To wit, PNM continues to target above-industry-average bottom-line growth of between 7% and 9% per year out to 2019. Key to reaching the mark will be PNM's ability to both earn authorized returns on its regulated businesses and minimize regulatory lag. Further additions to the rate base should also help. To that end, PSNM intends to invest approximately $720 million in power generation over the next four years (2016-2019) while transmission and distribution is expected to see a $460 million spend.

Dividends may rise at a slightly faster pace. Indeed, PNM has some upside flexibility, as the recent payout ratio was well below the upper end of its stated 50%-60% target range.

Shares of PNM Resources remain an average selection (Timeliness: 3) for relative year-ahead price performance. At the recent quotation, long-term total return potential doesn't stand out, either. Recent dividend hikes are encouraging, but more competitive yields can still be found elsewhere.

Nils C. Van Liew *April 29, 2016*

(A) EPS dil. Excl. n/r gains (losses): '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13, (16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due late February. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '15: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	35

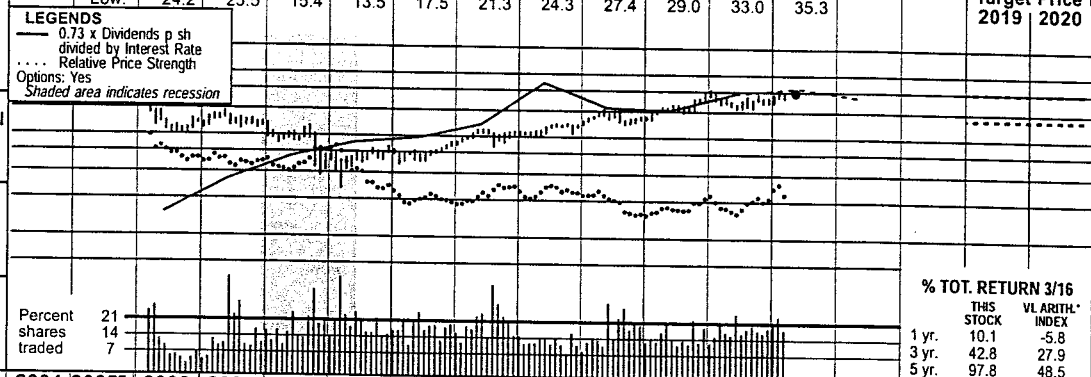
PORTLAND GENERAL NYSE-POR

RECENT PRICE 39.64 | P/E RATIO 18.3 (Trailing: 19.5 / Median: 15.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 1 Raised 3/18/16
SAFETY 2 Raised 5/4/12
TECHNICAL 2 Lowered 4/1/16
BETA .80 (1.00 = Market)

High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0	40.5
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0	35.3

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(Nil)	4%
Low	30	(-25%)	-3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	7
to Sell	0	0	0	2	0	1	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	112	113	125
to Sell	136	110	106
Hld's(000)	86966	86675	86623

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.1	-5.8
3 yr.	42.8	27.9
5 yr.	97.8	48.5

2000	2001	2002	2003	2004	2005F	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
--	--	--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	*22.20*	*23.00*	Revenues per sh	*25.00*
--	--	--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	*5.85*	*6.25*	"Cash Flow" per sh	*7.50*
--	--	--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	*2.25*	*2.50*	Earnings per sh A	*2.75*
--	--	--	--	--	--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	*1.26*	*1.34*	Div'd Decl'd per sh B ■ †	*1.60*
--	--	--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	*7.00*	*3.95*	Cap'l Spending per sh	*3.50*
--	--	--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	*26.35*	*27.45*	Book Value per sh C	*31.00*
--	--	--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	*89.00*	*89.20*	Common Shs Outst'g D	*89.80*
--	--	--	--	--	--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
--	--	--	--	--	--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	*Value Line*		Relative P/E Ratio	*.80*
--	--	--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $2210 mill. Due in 5 Yrs $572 mill.
LT Debt $2071 mill. LT Interest $108 mill.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $10 mill.

Pension Assets-12/15 $550 mill. Oblig. $758 mill.

Pfd Stock None

Common Stock 88,792,755 shs.

MARKET CAP: $3.5 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	1898.0	*1975*	*2050*	Revenues ($mill)	*2250*
71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	175.0	172.0	*200*	*220*	Net Profit ($mill)	*255*
33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	20.7%	*21.5%*	*21.5%*	Income Tax Rate	*21.5%*
33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	19.8%	*12.0%*	*5.0%*	AFUDC % to Net Profit	*3.0%*
43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	47.8%	*48.0%*	*47.5%*	Long-Term Debt Ratio	*47.0%*
56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	52.2%	*52.0%*	*52.5%*	Common Equity Ratio	*53.0%*
2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	4329.0	*4500*	*4675*	Total Capital ($mill)	*5250*
2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	6012.0	*6315*	*6330*	Net Plant ($mill)	*6100*
4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	5.4%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	*8.5%*	*9.0%*	Return on Com Equity E	*9.0%*
3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	3.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
39%	40%	69%	76%	62%	54%	57%	61%	50%	56%	*56%*	*54%*	All Div'ds to Net Prof	*56%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+1.2	-.8	+.6
Avg. Indust. Use (MWH)	16258	16577	17827
Avg. Indust. Revs. per KWH (¢)	4.84	5.13	5.01
Capacity at Peak (Mw)	4380	4910	4609
Peak Load, Winter (Mw)	3869	3866	3255
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.7	+1.2
Fixed Charge Cov. (%)	239	248	243

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	--	-2.0%	*1.5%*
"Cash Flow"	1.5%	4.0%	*5.5%*
Earnings	7.0%	6.5%	*5.5%*
Dividends	--	2.5%	*6.0%*
Book Value	2.5%	3.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	473.0	403.0	435.0	499.0	1810.0
2014	493.0	423.0	484.0	500.0	1900.0
2015	473.0	450.0	476.0	499.0	1898.0
2016	*500*	*460*	*505*	*510*	*1975*
2017	*540*	*470*	*515*	*525*	*2050*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	.55	2.18
2015	.62	.44	.40	.57	2.04
2016	*.70*	*.45*	*.45*	*.65*	*2.25*
2017	*.80*	*.50*	*.50*	*.70*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.265	.265	.27	.27	1.07
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30	.30			

BUSINESS: Portland General Electric Company (PGE) provides electricity to 852,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 35%; industrial, 12%; other, 6%. Generating sources: gas, 23%; coal, 19%; wind, 8%; hydro, 7%; purchased, 43%. Fuel costs: 35% of revenues. '15 reported depreciation rate: 3.6%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric is having problems with a large construction project. The utility is building the Carty 440-megawatt gas-fired generating station. Upon completion of the plant, it will receive an $85 million rate increase to recover the cost, provided that completion occurs by July 31st. The original schedule called for completion by then at a cost of $514 million. However, in December of 2015, PGE took over management of the project after it declared the contractor in default of the agreement. (Not surprisingly, the contractor disputes this.) The utility has been unable to collect a performance bond of $145.6 million because the insurers have denied liability. The disruption has caused the estimated cost to rise to $635 million-$670 million, and there is now a question of whether the facility will meet the July 31st deadline.

There is some regulatory risk here. If Carty is completed after July 31st, PGE would have to "pursue one or more alternative avenues" to place the plant into rates. If the utility meets the deadline, it would still have to seek recovery of the portion of Carty's construction cost that exceeds $514 million. Unrecovered costs would have to be written off.

We have reduced our 2016 earnings estimate by $0.10 a share. The weather in the first quarter was milder than normal. Our revised estimate, which is based on the assumption that Carty is completed by the July 31st deadline, is within management's guidance of $2.20-$2.35 a share.

We forecast solid profit improvement in 2017. That assumes a return to normal first-quarter weather patterns. Also, PGE will benefit from a full year of the rate hike for Carty.

The board of directors likely raised the dividend shortly after this report went to press. We estimate a $0.02-a-share (6.7%) quarterly increase. PGE has plenty of room for a hike in the disbursement, given that its payout ratio target is 50%-70%.

This timely stock has a dividend yield that is about average for a utility. With the recent quotation near the upper end of our 2019-2021 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *April 29, 2016*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. '15 earnings don't add due to rounding. Next earnings report due late July. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '15: $5.90/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '16: 9.6%; earned on avg. com. eq., '15: 8.3%. Regulatory Climate: Average. (F) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	70

WESTAR ENERGY NYSE-WR

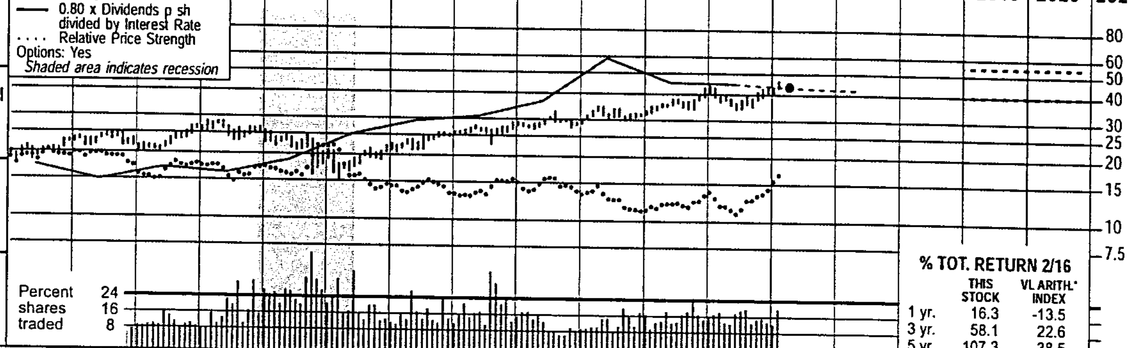
RECENT PRICE	43.69	P/E RATIO	19.2 (Trailing: 20.9 / Median: 14.0)	RELATIVE P/E RATIO	1.08	DIV'D YLD	3.5%	VALUE LINE

TIMELINESS **2** Raised 3/11/16
SAFETY **2** Raised 4/1/05
TECHNICAL **1** Raised 3/18/16
BETA .75 (1.00 = Market)

High:	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0	46.7
Low:	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9	40.0

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	9%
Low	40	(-10%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	16
to Sell	1	0	0	1	0	0	2	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	146	137	171
to Sell	125	121	117
Hld's(000)	97324	99969	100287

Percent shares traded 24 16 8

% TOT. RETURN 2/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.3	-13.5
3 yr.	58.1	22.6
5 yr.	107.3	38.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	17.40	*18.20*	*18.35*	Revenues per sh	*18.75*
6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	4.26	*4.65*	*4.85*	"Cash Flow" per sh	*5.50*
.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	2.09	*2.40*	*2.55*	Earnings per sh A	*3.10*
1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	1.44	*1.52*	*1.60*	Div'd Decl'd per sh B■†	*1.84*
4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	4.95	*7.60*	*5.15*	Cap'l Spending per sh	*6.50*
27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	25.98	*26.65*	*27.50*	Book Value per sh C	*29.80*
70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	141.35	*145.00*	*150.00*	Common Shs Outst'g E	*160.00*
20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	18.5	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*15.0*
1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	.94	*estimates*		Relative P/E Ratio	*.95*
7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	3.7%			Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $3414.0 mill. Due in 5 Yrs $700 mill.
LT Debt $3164.0 mill. LT Interest $125.0 mill.
(LT interest earned: 4.6x)

Pension Assets 12/15 $654 mill. Oblig. $864 mill.

Pfd Stock None

Common Stock 141,353,426 shs.
MARKET CAP: $6.2 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	2459.2	*2640*	*2750*	Revenues ($mill)	*3000*
165.3	168.4	136.8	141.3	203.9	214.0	275.1	292.5	313.3	291.9	*350*	*385*	Net Profit ($mill)	*495*
25.4%	27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	33.5%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	10.4%	--	--	--	--	--	--	10.4%	*10.0%*	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	*51.0%*	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
49.3%	48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	*49.0%*	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	6820.7	*6900*	*7000*	Total Capital ($mill)	*7500*
4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	*8500*	*8600*	*8700*	Net Plant ($mill)	*9000*
6.7%	5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	4.3%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.5%*
10.6%	9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	8.0%	*9.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	8.0%	*9.0%*	*10.0%*	Return on Com Equity D	*10.5%*
5.5%	4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	2.9%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
49%	53%	80%	87%	63%	65%	57%	56%	55%	69%	*63%*	*63%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+3.6	+1.5	-2.5
Avg. Indust. Use (MWH)	5407	5747	5654
Avg. Indust. Revs. per KWH (¢)	6.47	6.72	6.68
Capacity at Peak (Mw)	6671	6698	6772
Peak Load, Summer (Mw)	5489	5226	5167
Annual Load Factor (%)	55.9	56.2	56.1
% Change Customers (yr-end)	+.2	+.2	+.2
Fixed Charge Cov. (%)	323	332	330

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	-1.0%	1.5%	*2.5%*
"Cash Flow"	1.5%	5.0%	*4.5%*
Earnings	6.5%	9.0%	*6.0%*
Dividends	3.5%	3.5%	*3.0%*
Book Value	5.0%	3.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	546.2	569.6	695.0	559.9	2370.7
2014	628.6	612.7	764.0	596.4	2601.7
2015	590.8	589.6	732.8	546.0	2459.2
2016	*635*	*620*	*765*	*620*	*2640*
2017	*660*	*650*	*795*	*645*	*2750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.40	.52	1.04	.31	2.27
2014	.52	.40	1.10	.33	2.35
2015	.38	.46	.97	.28	2.09
2016	*.50*	*.45*	*1.05*	*.40*	*2.40*
2017	*.53*	*.48*	*1.10*	*.44*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.32	.33	.33	.33	1.31
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	1.39
2015	.35	.36	.36	.36	1.43
2016	.38				

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers in Kansas. Electric revenue sources: residential and rural, 39%; commercial, 33%; industrial, 28%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2015 depreciation rate: 4.0%. Estimated plant age: 17 years. Fuels: coal, 44%; nuclear, 8%; gas, 33%; renewable, 15%. Has 2,411 employees. BlackRock Inc owns 7.2% of common; The Vanguard Group owns 6.3%; Stowers Institute owns 5.7% (4/15 proxy). CEO and Pres.: Mark A. Ruelle. Inc.: Kansas. Addr.: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Westar Energy is building out its renewable energy portfolio. The company recently agreed to buy power from a 200-megawatt wind farm. The project is currently under construction and is expected to be operational by early 2017. This is in addition to the 280-megawatt wind farm being co-developed by Westar and Infinity Wind Power. That deal will involve more than $435 million in capital investment from both firms. In addition, Westar is in the process of shutting down many of its older coal-fired plants, as well as modernizing and improving the efficiency at some of its newer facilities. Management has done well in recent years preparing for tougher carbon emissions regulation.

The five-year capital expenditure plan has been updated. The new plan calls for $4.2 billion in capex, which is a 20% increase from last year's forecast, attributable to the additional renewable energy investments. The largest outlay ($1.1 billion) will be in 2016, and focus on transmission investments and upgrades at the La Cygne Energy Center and Wolf Creek. Annual expenditures should then drop to around $775 million.

The board of directors raised the dividend in the first quarter. The increase was $0.02 a share (5.6%), which was a bit more than expected. The annual distribution is now $1.52 a share. The company is targeting a slightly higher payout ratio (60%-75%) than previously indicated.

Earnings are poised to bounce back this year. A weak fourth quarter in 2015, largely due to the effects of the El Niño weather pattern, resulted in an 11% decrease in full-year profit. However, 2016 should be more favorable, thanks to a $78 million hike in base rates (approved in November) and a potential $22 million increase in transmission rates (expected to be approved in the first half of 2016). Management's full-year guidance is for earnings of $2.38 a share-$2.53 a share.

Conservative, income-oriented accounts may want to look here. Although the dividend yield is around the median for electric utilities, the payout should grow at a mid-single-digit rate over the next few years. Also, the Timeliness rank (2) and Safety rank (2) are both Above Average.

Daniel Henigson *March 18, 2016*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next egs. rep't due late May.
(B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2015: $5.31/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '15: 10.0%; earned on avg. com. eq., '15: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

EXHIBIT 2

MARKET PRICES - ALE

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	55.93	56.50	55.93	56.07	331,000	56.07
3/30/2016	57.38	57.38	55.71	55.87	571,200	55.87
3/29/2016	55.57	57.51	55.57	57.29	684,200	57.29
3/28/2016	57.57	58.00	56.97	57.22	93,300	57.22
3/24/2016	57.15	57.71	57.04	57.52	133,000	57.52
3/23/2016	56.63	57.46	56.11	57.21	171,400	57.21
3/22/2016	57.19	57.37	56.40	56.83	192,800	56.83
3/21/2016	57.25	57.56	56.34	57.27	188,100	57.27
3/18/2016	58.18	58.34	57.24	57.55	424,500	57.55
3/17/2016	56.50	57.93	56.50	57.82	251,500	57.82
3/16/2016	55.56	56.63	54.98	56.54	148,900	56.54
3/15/2016	55.58	55.96	55.50	55.60	112,500	55.60
3/14/2016	55.73	55.97	55.33	55.61	130,500	55.61
3/11/2016	56.50	56.57	55.55	55.83	247,000	55.83
3/10/2016	56.00	56.50	55.03	56.39	204,000	56.39
3/9/2016	55.65	56.24	55.01	56.17	204,400	56.17
3/8/2016	55.45	55.89	54.98	55.56	202,400	55.56
3/7/2016	54.74	55.47	54.64	55.36	203,700	55.36
3/4/2016	53.74	54.96	53.32	54.91	298,200	54.91
3/3/2016	53.11	54.02	52.29	54.00	317,000	54.00
3/2/2016	52.24	53.02	51.29	53.01	301,400	53.01
3/1/2016	53.27	53.47	52.02	52.30	284,900	52.30
2/29/2016	52.50	53.58	52.24	53.02	300,900	53.02
2/26/2016	54.03	54.03	52.54	52.55	216,200	52.55
2/25/2016	54.30	54.41	53.83	54.07	169,700	54.07
2/24/2016	53.10	54.11	53.10	54.10	206,400	54.10
2/23/2016	52.79	53.30	52.47	53.13	186,800	53.13
2/22/2016	52.70	53.46	52.55	53.04	180,800	53.04
2/19/2016	52.73	53.33	52.03	52.48	353,600	52.48
2/18/2016	50.94	53.60	50.83	53.08	419,300	53.08
2/17/2016	52.43	52.43	51.86	51.94	396,800	51.94
2/16/2016	52.75	52.91	52.26	52.43	209,600	52.43
2/12/2016	52.71	53.39	51.86	52.57	201,600	52.57
2/11/2016	52.55	53.16	51.59	52.50	341,800	52.50
2/10/2016	54.83	54.88	53.17	53.50	398,500	52.98
2/9/2016	53.39	54.88	53.10	54.65	319,000	54.12
2/8/2016	53.47	53.83	52.87	53.62	514,000	53.10
2/5/2016	53.77	54.00	52.91	53.45	333,000	52.93
2/4/2016	54.40	54.40	53.45	53.54	218,500	53.02
2/3/2016	54.05	54.96	53.73	54.38	406,500	53.85
2/2/2016	53.33	54.06	52.80	53.95	206,500	53.43
2/1/2016	52.71	53.79	52.42	53.54	272,800	53.02
1/29/2016	52.38	53.74	52.38	52.90	380,500	52.39
1/28/2016	51.16	52.09	50.68	51.97	192,700	51.46
1/27/2016	50.40	51.35	50.21	50.96	288,600	50.46
1/26/2016	49.68	50.57	49.67	50.55	197,700	50.06
1/25/2016	49.90	50.03	49.29	49.42	241,900	48.94
1/22/2016	49.18	50.15	49.02	50.02	644,500	49.53
1/21/2016	49.93	50.11	48.26	48.77	344,300	48.30
1/20/2016	50.41	50.63	49.17	49.80	568,400	49.32
1/19/2016	49.89	50.65	49.42	50.36	462,800	49.87
1/15/2016	49.08	50.08	48.79	49.49	346,300	49.01
1/14/2016	49.91	50.66	49.56	50.29	400,100	49.80
1/13/2016	50.20	50.63	49.67	49.88	232,900	49.40
1/12/2016	50.97	50.97	49.72	50.20	193,400	49.71
1/11/2016	50.03	50.81	50.01	50.66	233,300	50.17
1/8/2016	49.76	50.52	49.70	49.86	209,900	49.38
1/7/2016	49.43	50.20	49.43	49.68	486,300	49.20
1/6/2016	49.46	50.16	49.26	50.02	209,600	49.53
1/5/2016	50.12	50.18	49.07	49.88	278,900	49.40
1/4/2016	50.42	50.82	49.38	49.72	388,800	49.24

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 53.31

ALLETE, Inc. (ALE) - NYSE ★ Watchlist

54.24 **1.64(2.93%)** 1:32PM EDT - NYSE Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	55.93	56.50	55.93	56.07	331,000	56.07
Mar 30, 2016	57.38	57.38	55.71	55.87	571,200	55.87
Mar 29, 2016	55.57	57.51	55.57	57.29	684,200	57.29
Mar 28, 2016	57.57	58.00	56.97	57.22	93,300	57.22
Mar 24, 2016	57.15	57.71	57.04	57.52	133,000	57.52
Mar 23, 2016	56.63	57.46	56.11	57.21	171,400	57.21
Mar 22, 2016	57.19	57.37	56.40	56.83	192,800	56.83
Mar 21, 2016	57.25	57.56	56.34	57.27	188,100	57.27
Mar 18, 2016	58.18	58.34	57.24	57.55	424,500	57.55
Mar 17, 2016	56.50	57.93	56.50	57.82	251,500	57.82
Mar 16, 2016	55.56	56.63	54.98	56.54	148,900	56.54
Mar 15, 2016	55.58	55.96	55.50	55.60	112,500	55.60
Mar 14, 2016	55.73	55.97	55.33	55.61	130,500	55.61
Mar 11, 2016	56.50	56.57	55.55	55.83	247,000	55.83
Mar 10, 2016	56.00	56.50	55.03	56.39	204,000	56.39
Mar 9, 2016	55.65	56.24	55.01	56.17	204,400	56.17
Mar 8, 2016	55.45	55.89	54.98	55.56	202,400	55.56
Mar 7, 2016	54.74	55.47	54.64	55.36	203,700	55.36
Mar 4, 2016	53.74	54.96	53.32	54.91	298,200	54.91
Mar 3, 2016	53.11	54.02	52.29	54.00	317,000	54.00
Mar 2, 2016	52.24	53.02	51.29	53.01	301,400	53.01
Mar 1, 2016	53.27	53.47	52.02	52.30	284,900	52.30
Feb 29, 2016	52.50	53.58	52.24	53.02	300,900	53.02
Feb 26, 2016	54.03	54.03	52.54	52.55	216,200	52.55
Feb 25, 2016	54.30	54.41	53.83	54.07	169,700	54.07
Feb 24, 2016	53.10	54.11	53.10	54.10	206,400	54.10
Feb 23, 2016	52.79	53.30	52.47	53.13	186,800	53.13
Feb 22, 2016	52.70	53.46	52.55	53.04	180,800	53.04
Feb 19, 2016	52.73	53.33	52.03	52.48	353,600	52.48
Feb 18, 2016	50.94	53.60	50.83	53.08	419,300	53.08
Feb 17, 2016	52.43	52.43	51.86	51.94	396,800	51.94
Feb 16, 2016	52.75	52.91	52.26	52.43	209,600	52.43
Feb 12, 2016	52.71	53.39	51.86	52.57	201,600	52.57
Feb 11, 2016	52.55	53.16	51.59	52.50	341,800	52.50
Feb 11, 2016			0.52 Dividend			

Feb 10, 2016	54.83	54.88	53.17	53.50	398,500	52.98
Feb 9, 2016	53.39	54.88	53.10	54.65	319,000	54.12
Feb 8, 2016	53.47	53.83	52.87	53.62	514,000	53.10
Feb 5, 2016	53.77	54.00	52.91	53.45	333,000	52.93
Feb 4, 2016	54.40	54.40	53.45	53.54	218,500	53.02
Feb 3, 2016	54.05	54.96	53.73	54.38	406,500	53.85
Feb 2, 2016	53.33	54.06	52.80	53.95	206,500	53.43
Feb 1, 2016	52.71	53.79	52.42	53.54	272,800	53.02
Jan 29, 2016	52.38	53.74	52.38	52.90	380,500	52.39
Jan 28, 2016	51.16	52.09	50.68	51.97	192,700	51.46
Jan 27, 2016	50.40	51.35	50.21	50.96	288,600	50.46
Jan 26, 2016	49.68	50.57	49.67	50.55	197,700	50.06
Jan 25, 2016	49.90	50.03	49.29	49.42	241,900	48.94
Jan 22, 2016	49.18	50.15	49.02	50.02	644,500	49.53
Jan 21, 2016	49.93	50.11	48.26	48.77	344,300	48.30
Jan 20, 2016	50.41	50.63	49.17	49.80	568,400	49.32
Jan 19, 2016	49.89	50.65	49.42	50.36	462,800	49.87
Jan 15, 2016	49.08	50.08	48.79	49.49	346,300	49.01
Jan 14, 2016	49.91	50.66	49.56	50.29	400,100	49.80
Jan 13, 2016	50.20	50.63	49.67	49.88	232,900	49.40
Jan 12, 2016	50.97	50.97	49.72	50.20	193,400	49.71
Jan 11, 2016	50.03	50.81	50.01	50.66	233,300	50.17
Jan 8, 2016	49.76	50.52	49.70	49.86	209,900	49.38
Jan 7, 2016	49.43	50.20	49.43	49.68	486,300	49.20
Jan 6, 2016	49.46	50.16	49.26	50.02	209,600	49.53
Jan 5, 2016	50.12	50.18	49.07	49.88	278,900	49.40
Jan 4, 2016	50.42	50.82	49.38	49.72	388,800	49.24

* Close price adjusted for dividends and splits.

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Download to Spreadsheet

Currency in USD.

MARKET PRICES - AEP

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	66.01	66.49	65.77	66.40	2,751,100	66.40
3/30/2016	66.06	66.37	65.70	66.02	2,277,900	66.02
3/29/2016	65.14	66.07	64.82	66.03	3,027,700	66.03
3/28/2016	65.39	65.76	64.88	65.00	3,282,600	65.00
3/24/2016	65.02	65.40	64.72	65.06	3,984,900	65.06
3/23/2016	64.64	65.31	64.40	65.08	3,697,200	65.08
3/22/2016	65.01	65.34	64.57	64.77	2,764,900	64.77
3/21/2016	64.39	65.03	64.02	64.80	2,289,900	64.80
3/18/2016	65.64	65.68	64.78	64.79	4,994,300	64.79
3/17/2016	65.20	65.63	64.85	65.43	2,374,100	65.43
3/16/2016	64.33	65.25	63.73	65.13	2,906,800	65.13
3/15/2016	64.26	64.70	63.87	64.41	1,592,900	64.41
3/14/2016	63.89	64.38	63.72	64.22	1,536,200	64.22
3/11/2016	64.56	64.69	64.09	64.23	2,088,500	64.23
3/10/2016	64.30	64.44	63.48	64.13	1,951,300	64.13
3/9/2016	63.68	64.63	63.55	64.30	2,323,700	64.30
3/8/2016	63.24	63.92	62.91	63.61	2,693,500	63.61
3/7/2016	62.41	63.40	62.17	63.24	2,702,500	63.24
3/4/2016	61.46	62.71	61.02	62.43	3,827,000	62.43
3/3/2016	61.78	61.85	60.66	61.77	3,874,200	61.77
3/2/2016	61.51	61.97	60.15	61.89	2,729,700	61.89
3/1/2016	62.07	62.27	61.25	61.73	2,051,300	61.73
2/29/2016	61.47	62.39	61.44	61.75	2,951,700	61.75
2/26/2016	63.28	63.77	61.42	61.47	3,312,400	61.47
2/25/2016	63.17	63.90	63.02	63.89	1,754,200	63.89
2/24/2016	62.78	63.30	62.40	63.01	1,760,600	63.01
2/23/2016	62.47	62.94	62.10	62.76	1,933,200	62.76
2/22/2016	62.01	62.88	61.85	62.85	2,209,000	62.85
2/19/2016	62.43	62.45	61.59	61.91	2,442,100	61.91
2/18/2016	61.29	62.78	60.92	62.45	2,923,900	62.45
2/17/2016	61.12	61.28	60.33	61.10	3,384,200	61.10
2/16/2016	60.92	61.56	60.50	61.09	3,900,900	61.09
2/12/2016	61.31	61.85	60.41	60.60	3,841,900	60.60
2/11/2016	62.53	63.00	61.28	61.31	3,268,400	61.31
2/10/2016	62.06	63.38	61.55	62.90	4,180,300	62.90
2/9/2016	62.40	62.93	61.95	62.37	3,166,400	62.37
2/8/2016	62.23	63.05	61.38	62.49	4,545,200	62.49
2/5/2016	62.17	63.28	61.55	62.84	4,123,000	62.28
2/4/2016	63.15	63.34	62.03	62.29	4,114,600	61.73
2/3/2016	62.38	63.63	62.18	63.31	4,944,000	62.75
2/2/2016	61.66	62.30	61.50	62.00	4,599,000	61.45
2/1/2016	61.00	62.56	60.82	61.79	5,033,500	61.24
1/29/2016	60.00	61.08	59.96	60.97	4,726,900	60.43
1/28/2016	57.13	59.84	56.75	59.45	4,542,500	58.92
1/27/2016	58.19	58.80	57.68	58.19	3,125,500	57.67
1/26/2016	58.00	58.97	57.87	58.20	3,176,500	57.68
1/25/2016	58.54	58.56	57.67	57.75	3,639,700	57.24
1/22/2016	58.46	58.57	57.72	58.53	3,707,600	58.01
1/21/2016	57.38	58.38	57.10	57.64	3,990,500	57.13
1/20/2016	59.21	59.46	57.17	57.92	4,403,300	57.40
1/19/2016	59.00	59.72	58.70	59.57	3,620,700	59.04
1/15/2016	58.36	59.09	57.88	58.69	3,577,300	58.17
1/14/2016	58.28	59.56	57.90	59.14	4,091,600	58.61
1/13/2016	58.23	58.54	57.82	57.95	3,531,500	57.43
1/12/2016	58.89	58.97	57.46	58.17	4,252,100	57.65
1/11/2016	58.38	59.00	58.21	58.77	2,763,500	58.25
1/8/2016	58.35	58.93	58.13	58.26	2,795,400	57.74
1/7/2016	58.47	58.98	58.17	58.35	3,847,200	57.83
1/6/2016	58.43	59.35	58.21	59.03	3,528,300	58.50
1/5/2016	58.25	58.98	57.31	58.81	3,434,500	58.29
1/4/2016	57.82	58.36	57.53	58.33	4,087,800	57.81

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 61.84

American Electric Power Co., Inc. (AEP) - NYSE ★ Watchlist Like 62

65.55 1.03(1.55%) 2:38PM EDT - Nasdaq Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

(●) Daily
( ) Weekly
( ) Monthly
( ) Dividends Only

Get Prices

First | Previous | Next | Last

Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	66.01	66.49	65.77	66.40	2,751,100	66.40
Mar 30, 2016	66.06	66.37	65.70	66.02	2,277,900	66.02
Mar 29, 2016	65.14	66.07	64.82	66.03	3,027,700	66.03
Mar 28, 2016	65.39	65.76	64.88	65.00	3,282,600	65.00
Mar 24, 2016	65.02	65.40	64.72	65.06	3,984,900	65.06
Mar 23, 2016	64.64	65.31	64.40	65.08	3,697,200	65.08
Mar 22, 2016	65.01	65.34	64.57	64.77	2,764,900	64.77
Mar 21, 2016	64.39	65.03	64.02	64.80	2,289,900	64.80
Mar 18, 2016	65.64	65.68	64.78	64.79	4,994,300	64.79
Mar 17, 2016	65.20	65.63	64.85	65.43	2,374,100	65.43
Mar 16, 2016	64.33	65.25	63.73	65.13	2,906,800	65.13
Mar 15, 2016	64.26	64.70	63.87	64.41	1,592,900	64.41
Mar 14, 2016	63.89	64.38	63.72	64.22	1,536,200	64.22
Mar 11, 2016	64.56	64.69	64.09	64.23	2,088,500	64.23
Mar 10, 2016	64.30	64.44	63.48	64.13	1,951,300	64.13
Mar 9, 2016	63.68	64.63	63.55	64.30	2,323,700	64.30
Mar 8, 2016	63.24	63.92	62.91	63.61	2,693,500	63.61
Mar 7, 2016	62.41	63.40	62.17	63.24	2,702,500	63.24
Mar 4, 2016	61.46	62.71	61.02	62.43	3,827,000	62.43
Mar 3, 2016	61.78	61.85	60.66	61.77	3,874,200	61.77
Mar 2, 2016	61.51	61.97	60.15	61.89	2,729,700	61.89
Mar 1, 2016	62.07	62.27	61.25	61.73	2,051,300	61.73
Feb 29, 2016	61.47	62.39	61.44	61.75	2,951,700	61.75
Feb 26, 2016	63.28	63.77	61.42	61.47	3,312,400	61.47
Feb 25, 2016	63.17	63.90	63.02	63.89	1,754,200	63.89
Feb 24, 2016	62.78	63.30	62.40	63.01	1,760,600	63.01
Feb 23, 2016	62.47	62.94	62.10	62.76	1,933,200	62.76
Feb 22, 2016	62.01	62.88	61.85	62.85	2,209,000	62.85
Feb 19, 2016	62.43	62.45	61.59	61.91	2,442,100	61.91
Feb 18, 2016	61.29	62.78	60.92	62.45	2,923,900	62.45
Feb 17, 2016	61.12	61.28	60.33	61.10	3,384,200	61.10
Feb 16, 2016	60.92	61.56	60.50	61.09	3,900,900	61.09
Feb 12, 2016	61.31	61.85	60.41	60.60	3,841,900	60.60
Feb 11, 2016	62.53	63.00	61.28	61.31	3,268,400	61.31
Feb 10, 2016	62.06	63.38	61.55	62.90	4,180,300	62.90

Feb 9, 2016	62.40	62.93	61.95	62.37	3,166,400	62.37
Feb 8, 2016	62.23	63.05	61.38	62.49	4,545,200	62.49
Feb 8, 2016	0.56 Dividend					
Feb 5, 2016	62.17	63.28	61.55	62.84	4,123,000	62.28
Feb 4, 2016	63.15	63.34	62.03	62.29	4,114,600	61.73
Feb 3, 2016	62.38	63.63	62.18	63.31	4,944,000	62.75
Feb 2, 2016	61.66	62.30	61.50	62.00	4,599,000	61.45
Feb 1, 2016	61.00	62.56	60.82	61.79	5,033,500	61.24
Jan 29, 2016	60.00	61.08	59.96	60.97	4,726,900	60.43
Jan 28, 2016	57.13	59.84	56.75	59.45	4,542,500	58.92
Jan 27, 2016	58.19	58.80	57.68	58.19	3,125,500	57.67
Jan 26, 2016	58.00	58.97	57.87	58.20	3,176,500	57.68
Jan 25, 2016	58.54	58.56	57.67	57.75	3,639,700	57.24
Jan 22, 2016	58.46	58.57	57.72	58.53	3,707,600	58.01
Jan 21, 2016	57.38	58.38	57.10	57.64	3,990,500	57.13
Jan 20, 2016	59.21	59.46	57.17	57.92	4,403,300	57.40
Jan 19, 2016	59.00	59.72	58.70	59.57	3,620,700	59.04
Jan 15, 2016	58.36	59.09	57.88	58.69	3,577,300	58.17
Jan 14, 2016	58.28	59.56	57.90	59.14	4,091,600	58.61
Jan 13, 2016	58.23	58.54	57.82	57.95	3,531,500	57.43
Jan 12, 2016	58.89	58.97	57.46	58.17	4,252,100	57.65
Jan 11, 2016	58.38	59.00	58.21	58.77	2,763,500	58.25
Jan 8, 2016	58.35	58.93	58.13	58.26	2,795,400	57.74
Jan 7, 2016	58.47	58.98	58.17	58.35	3,847,200	57.83
Jan 6, 2016	58.43	59.35	58.21	59.03	3,528,300	58.50
Jan 5, 2016	58.25	58.98	57.31	58.81	3,434,500	58.29
Jan 4, 2016	57.82	58.36	57.53	58.33	4,087,800	57.81

* Close price adjusted for dividends and splits.

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Currency in USD.

MARKET PRICES - EE

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	45.89	46.10	45.70	45.88	200,900	45.88
3/30/2016	46.07	46.20	45.64	45.81	170,500	45.81
3/29/2016	44.64	46.12	44.64	46.04	244,000	46.04
3/28/2016	44.77	45.11	43.99	44.50	129,600	44.50
3/24/2016	44.82	44.97	44.00	44.74	272,400	44.74
3/23/2016	43.93	44.28	43.61	43.98	142,700	43.98
3/22/2016	44.05	44.29	43.79	43.95	123,300	43.95
3/21/2016	43.88	44.12	43.26	44.10	172,200	44.10
3/18/2016	44.31	44.31	43.74	44.19	349,600	44.19
3/17/2016	43.05	44.19	42.93	44.08	214,100	44.08
3/16/2016	42.87	43.53	42.31	43.08	135,100	43.08
3/15/2016	42.79	43.41	42.75	42.89	158,900	42.89
3/14/2016	42.89	43.02	42.44	42.98	186,400	42.98
3/11/2016	42.97	43.14	42.57	42.92	196,900	42.92
3/10/2016	42.46	43.09	42.46	42.98	236,600	42.69
3/9/2016	42.40	42.78	42.31	42.60	164,900	42.31
3/8/2016	41.49	42.74	41.17	42.52	256,700	42.23
3/7/2016	41.29	41.65	41.03	41.48	191,600	41.20
3/4/2016	40.87	41.53	40.52	41.45	176,300	41.17
3/3/2016	40.78	41.11	40.14	41.05	191,400	40.77
3/2/2016	40.12	40.86	39.37	40.76	256,000	40.48
3/1/2016	41.04	41.33	39.92	40.30	213,400	40.02
2/29/2016	40.40	41.17	40.28	40.85	268,300	40.57
2/26/2016	41.49	42.10	40.32	40.55	357,500	40.27
2/25/2016	42.82	43.22	41.79	41.90	295,200	41.61
2/24/2016	40.80	43.04	40.66	42.76	359,700	42.47
2/23/2016	40.49	41.11	40.30	40.79	341,300	40.51
2/22/2016	40.88	41.18	40.64	40.76	198,400	40.48
2/19/2016	40.82	40.92	40.28	40.71	181,000	40.43
2/18/2016	40.13	40.91	39.99	40.91	441,500	40.63
2/17/2016	40.20	40.38	39.68	40.06	139,500	39.79
2/16/2016	40.62	40.78	39.95	40.17	205,700	39.89
2/12/2016	39.72	40.74	39.72	40.31	364,600	40.03
2/11/2016	40.57	41.73	40.11	40.12	388,500	39.84
2/10/2016	41.37	41.64	40.64	40.78	503,000	40.50
2/9/2016	41.01	41.64	40.77	41.22	201,200	40.94
2/8/2016	41.34	42.36	40.91	41.14	364,100	40.86
2/5/2016	41.72	42.25	41.19	41.29	452,000	41.01
2/4/2016	42.52	43.02	41.73	41.75	264,500	41.46
2/3/2016	42.96	43.40	42.08	42.64	747,900	42.35
2/2/2016	42.36	42.96	42.05	42.77	372,100	42.48
2/1/2016	41.01	42.66	40.74	42.54	507,400	42.25
1/29/2016	39.70	41.24	39.70	40.93	414,200	40.65
1/28/2016	38.22	39.59	38.00	39.44	193,800	39.17
1/27/2016	38.18	38.61	37.92	38.19	105,100	37.93
1/26/2016	37.89	38.39	37.89	38.29	227,900	38.03
1/25/2016	38.56	38.56	37.66	37.78	111,800	37.52
1/22/2016	37.41	38.73	37.41	38.60	220,000	38.34
1/21/2016	38.01	38.07	37.20	37.31	268,500	37.05
1/20/2016	38.47	38.55	37.19	37.98	155,300	37.72
1/19/2016	38.63	38.83	38.29	38.70	176,300	38.43
1/15/2016	38.45	38.92	37.79	38.44	164,400	38.18
1/14/2016	38.57	39.50	38.42	39.18	169,800	38.91
1/13/2016	38.44	38.85	38.15	38.54	207,500	38.28
1/12/2016	38.76	38.76	38.08	38.44	208,700	38.18
1/11/2016	38.28	38.75	38.21	38.59	204,400	38.33
1/8/2016	38.17	38.66	38.07	38.22	142,100	37.96
1/7/2016	38.25	38.68	38.11	38.14	301,000	37.88
1/6/2016	38.08	38.97	38.08	38.71	164,600	38.44
1/5/2016	37.99	38.48	37.49	38.36	140,600	38.10
1/4/2016	38.36	38.91	37.69	37.91	222,400	37.65

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 41.12

El Paso Electric Co. (EE) - NYSE

45.26 **1.00(2.16%)** 2:39PM EDT - Nasdaq Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

Daily
Weekly
Monthly
Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	45.89	46.10	45.70	45.88	200,900	45.88
Mar 30, 2016	46.07	46.20	45.64	45.81	170,500	45.81
Mar 29, 2016	44.64	46.12	44.64	46.04	244,000	46.04
Mar 28, 2016	44.77	45.11	43.99	44.50	129,600	44.50
Mar 24, 2016	44.82	44.97	44.00	44.74	272,400	44.74
Mar 23, 2016	43.93	44.28	43.61	43.98	142,700	43.98
Mar 22, 2016	44.05	44.29	43.79	43.95	123,300	43.95
Mar 21, 2016	43.88	44.12	43.26	44.10	172,200	44.10
Mar 18, 2016	44.31	44.31	43.74	44.19	349,600	44.19
Mar 17, 2016	43.05	44.19	42.93	44.08	214,100	44.08
Mar 16, 2016	42.87	43.53	42.31	43.08	135,100	43.08
Mar 15, 2016	42.79	43.41	42.75	42.89	158,900	42.89
Mar 14, 2016	42.89	43.02	42.44	42.98	186,400	42.98
Mar 11, 2016	42.97	43.14	42.57	42.92	196,900	42.92
Mar 11, 2016	0.295 Dividend					
Mar 10, 2016	42.46	43.09	42.46	42.98	236,600	42.69
Mar 9, 2016	42.40	42.78	42.31	42.60	164,900	42.31
Mar 8, 2016	41.49	42.74	41.17	42.52	256,700	42.23
Mar 7, 2016	41.29	41.65	41.03	41.48	191,600	41.20
Mar 4, 2016	40.87	41.53	40.52	41.45	176,300	41.17
Mar 3, 2016	40.78	41.11	40.14	41.05	191,400	40.77
Mar 2, 2016	40.12	40.86	39.37	40.76	256,000	40.48
Mar 1, 2016	41.04	41.33	39.92	40.30	213,400	40.02
Feb 29, 2016	40.40	41.17	40.28	40.85	268,300	40.57
Feb 26, 2016	41.49	42.10	40.32	40.55	357,500	40.27
Feb 25, 2016	42.82	43.22	41.79	41.90	295,200	41.61
Feb 24, 2016	40.80	43.04	40.66	42.76	359,700	42.47
Feb 23, 2016	40.49	41.11	40.30	40.79	341,300	40.51
Feb 22, 2016	40.88	41.18	40.64	40.76	198,400	40.48
Feb 19, 2016	40.82	40.92	40.28	40.71	181,000	40.43
Feb 18, 2016	40.13	40.91	39.99	40.91	441,500	40.63
Feb 17, 2016	40.20	40.38	39.68	40.06	139,500	39.79
Feb 16, 2016	40.62	40.78	39.95	40.17	205,700	39.89
Feb 12, 2016	39.72	40.74	39.72	40.31	364,600	40.03
Feb 11, 2016	40.57	41.73	40.11	40.12	388,500	39.84

Feb 10, 2016	41.37	41.64	40.64	40.78	503,000	40.50
Feb 9, 2016	41.01	41.64	40.77	41.22	201,200	40.94
Feb 8, 2016	41.34	42.36	40.91	41.14	364,100	40.86
Feb 5, 2016	41.72	42.25	41.19	41.29	452,000	41.01
Feb 4, 2016	42.52	43.02	41.73	41.75	264,500	41.46
Feb 3, 2016	42.96	43.40	42.08	42.64	747,900	42.35
Feb 2, 2016	42.36	42.96	42.05	42.77	372,100	42.48
Feb 1, 2016	41.01	42.66	40.74	42.54	507,400	42.25
Jan 29, 2016	39.70	41.24	39.70	40.93	414,200	40.65
Jan 28, 2016	38.22	39.59	38.00	39.44	193,800	39.17
Jan 27, 2016	38.18	38.61	37.92	38.19	105,100	37.93
Jan 26, 2016	37.89	38.39	37.89	38.29	227,900	38.03
Jan 25, 2016	38.56	38.56	37.66	37.78	111,800	37.52
Jan 22, 2016	37.41	38.73	37.41	38.60	220,000	38.34
Jan 21, 2016	38.01	38.07	37.20	37.31	268,500	37.05
Jan 20, 2016	38.47	38.55	37.19	37.98	155,300	37.72
Jan 19, 2016	38.63	38.83	38.29	38.70	176,300	38.43
Jan 15, 2016	38.45	38.92	37.79	38.44	164,400	38.18
Jan 14, 2016	38.57	39.50	38.42	39.18	169,800	38.91
Jan 13, 2016	38.44	38.85	38.15	38.54	207,500	38.28
Jan 12, 2016	38.76	38.76	38.08	38.44	208,700	38.18
Jan 11, 2016	38.28	38.75	38.21	38.59	204,400	38.33
Jan 8, 2016	38.17	38.66	38.07	38.22	142,100	37.96
Jan 7, 2016	38.25	38.68	38.11	38.14	301,000	37.88
Jan 6, 2016	38.08	38.97	38.08	38.71	164,600	38.44
Jan 5, 2016	37.99	38.48	37.49	38.36	140,600	38.10
Jan 4, 2016	38.36	38.91	37.69	37.91	222,400	37.65

* Close price adjusted for dividends and splits.

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Currency in USD.

MARKET PRICES - EDE

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	33.28	33.31	32.96	33.05	464,200	33.05
3/30/2016	33.54	33.58	33.28	33.31	211,300	33.31
3/29/2016	32.88	33.72	32.88	33.68	439,500	33.68
3/28/2016	33.26	33.35	32.77	32.86	368,600	32.86
3/24/2016	33.04	33.40	33.02	33.36	284,700	33.36
3/23/2016	33.17	33.20	32.96	32.96	160,600	32.96
3/22/2016	33.17	33.23	33.16	33.16	130,000	33.16
3/21/2016	33.24	33.30	33.16	33.16	180,000	33.16
3/18/2016	33.40	33.40	33.16	33.30	362,200	33.30
3/17/2016	33.21	33.43	33.08	33.32	277,600	33.32
3/16/2016	33.06	33.41	32.97	33.39	262,700	33.39
3/15/2016	33.00	33.20	32.98	33.17	160,200	33.17
3/14/2016	33.50	33.50	33.00	33.01	171,100	33.01
3/11/2016	33.34	33.50	33.30	33.48	391,300	33.48
3/10/2016	33.30	33.40	33.20	33.32	429,800	33.32
3/9/2016	33.17	33.37	33.00	33.33	331,300	33.33
3/8/2016	33.26	33.41	33.13	33.13	435,400	33.13
3/7/2016	33.13	33.39	33.11	33.32	277,300	33.32
3/4/2016	32.94	33.21	32.87	33.21	360,600	33.21
3/3/2016	32.91	33.17	32.79	33.08	412,600	33.08
3/2/2016	32.90	33.08	32.70	32.91	350,400	32.91
3/1/2016	32.75	33.21	32.75	32.92	346,500	32.92
2/29/2016	32.81	33.09	32.70	32.72	693,700	32.72
2/26/2016	33.37	33.50	32.71	32.76	636,800	32.76
2/25/2016	33.17	33.67	33.10	33.67	590,700	33.41
2/24/2016	33.08	33.40	33.08	33.24	645,300	32.98
2/23/2016	33.35	33.55	33.14	33.15	515,200	32.89
2/22/2016	33.52	33.60	33.18	33.50	835,900	33.24
2/19/2016	33.38	33.75	33.24	33.54	1,322,000	33.28
2/18/2016	33.10	33.73	33.08	33.32	743,000	33.06
2/17/2016	33.05	33.19	32.84	33.15	787,200	32.89
2/16/2016	32.99	33.30	32.95	33.06	966,300	32.80
2/12/2016	32.97	33.09	32.64	32.99	1,047,000	32.74
2/11/2016	32.67	33.00	32.61	32.74	2,103,700	32.49
2/10/2016	32.10	33.13	32.10	33.06	6,322,300	32.80
2/9/2016	27.78	28.26	27.58	28.20	379,900	27.98
2/8/2016	28.55	28.73	27.38	28.04	353,300	27.82
2/5/2016	28.20	29.39	27.11	28.71	478,500	28.49
2/4/2016	29.49	29.59	28.99	29.45	267,800	29.22
2/3/2016	29.93	30.18	29.22	29.53	340,600	29.30
2/2/2016	29.55	30.00	29.24	29.78	407,800	29.55
2/1/2016	29.28	30.09	29.28	29.70	458,100	29.47
1/29/2016	28.86	29.36	28.85	29.34	474,200	29.11
1/28/2016	28.70	29.25	28.66	28.70	346,400	28.48
1/27/2016	28.92	29.06	28.72	28.79	298,900	28.57
1/26/2016	28.39	29.09	28.38	29.07	396,200	28.85
1/25/2016	28.51	28.60	28.15	28.36	501,600	28.14
1/22/2016	27.11	29.15	27.00	28.65	1,696,400	28.43
1/21/2016	27.64	27.72	26.20	26.55	600,100	26.34
1/20/2016	27.84	27.94	26.76	27.53	243,100	27.32
1/19/2016	27.54	28.09	27.54	27.94	237,100	27.72
1/15/2016	27.75	27.91	27.15	27.69	277,100	27.48
1/14/2016	27.55	28.69	27.55	28.22	382,000	28.00
1/13/2016	27.76	27.90	27.39	27.50	217,000	27.29
1/12/2016	27.93	27.93	27.27	27.76	259,300	27.55
1/11/2016	27.51	27.98	27.51	27.72	303,200	27.51
1/8/2016	27.70	27.99	27.43	27.61	487,500	27.40
1/7/2016	28.10	28.18	27.62	27.62	486,800	27.41
1/6/2016	27.57	28.42	27.31	28.26	481,700	28.04
1/5/2016	27.99	27.99	27.09	27.66	353,600	27.45
1/4/2016	27.86	27.90	27.25	27.78	633,400	27.57

AVERAGE STOCK PRICE FOR
THREE MONTH PERIOD

$ 31.11

The Empire District Electric Company (EDE) - NYSE ★ Watchlist

33.25 0.05(0.15%) 2:39PM EDT - NYSE Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	33.28	33.31	32.96	33.05	464,200	33.05
Mar 30, 2016	33.54	33.58	33.28	33.31	211,300	33.31
Mar 29, 2016	32.88	33.72	32.88	33.68	439,500	33.68
Mar 28, 2016	33.26	33.35	32.77	32.86	368,600	32.86
Mar 24, 2016	33.04	33.40	33.02	33.36	284,700	33.36
Mar 23, 2016	33.17	33.20	32.96	32.96	160,600	32.96
Mar 22, 2016	33.17	33.23	33.16	33.16	130,000	33.16
Mar 21, 2016	33.24	33.30	33.16	33.16	180,000	33.16
Mar 18, 2016	33.40	33.40	33.16	33.30	362,200	33.30
Mar 17, 2016	33.21	33.43	33.08	33.32	277,600	33.32
Mar 16, 2016	33.06	33.41	32.97	33.39	262,700	33.39
Mar 15, 2016	33.00	33.20	32.98	33.17	160,200	33.17
Mar 14, 2016	33.50	33.50	33.00	33.01	171,100	33.01
Mar 11, 2016	33.34	33.50	33.30	33.48	391,300	33.48
Mar 10, 2016	33.30	33.40	33.20	33.32	429,800	33.32
Mar 9, 2016	33.17	33.37	33.00	33.33	331,300	33.33
Mar 8, 2016	33.26	33.41	33.13	33.13	435,400	33.13
Mar 7, 2016	33.13	33.39	33.11	33.32	277,300	33.32
Mar 4, 2016	32.94	33.21	32.87	33.21	360,600	33.21
Mar 3, 2016	32.91	33.17	32.79	33.08	412,600	33.08
Mar 2, 2016	32.90	33.08	32.70	32.91	350,400	32.91
Mar 1, 2016	32.75	33.21	32.75	32.92	346,500	32.92
Feb 29, 2016	32.81	33.09	32.70	32.72	693,700	32.72
Feb 26, 2016	33.37	33.50	32.71	32.76	636,800	32.76
Feb 26, 2016	0.26 Dividend					
Feb 25, 2016	33.17	33.67	33.10	33.67	590,700	33.41
Feb 24, 2016	33.08	33.40	33.08	33.24	645,300	32.98
Feb 23, 2016	33.35	33.55	33.14	33.15	515,200	32.89
Feb 22, 2016	33.52	33.60	33.18	33.50	835,900	33.24
Feb 19, 2016	33.38	33.75	33.24	33.54	1,322,000	33.28
Feb 18, 2016	33.10	33.73	33.08	33.32	743,000	33.06
Feb 17, 2016	33.05	33.19	32.84	33.15	787,200	32.89
Feb 16, 2016	32.99	33.30	32.95	33.06	966,300	32.80
Feb 12, 2016	32.97	33.09	32.64	32.99	1,047,000	32.74
Feb 11, 2016	32.67	33.00	32.61	32.74	2,103,700	32.49

Feb 10, 2016	32.10	33.13	32.10	33.06	6,322,300	32.80
Feb 9, 2016	27.78	28.26	27.58	28.20	379,900	27.98
Feb 8, 2016	28.55	28.73	27.38	28.04	353,300	27.82
Feb 5, 2016	28.20	29.39	27.11	28.71	478,500	28.49
Feb 4, 2016	29.49	29.59	28.99	29.45	267,800	29.22
Feb 3, 2016	29.93	30.18	29.22	29.53	340,600	29.30
Feb 2, 2016	29.55	30.00	29.24	29.78	407,800	29.55
Feb 1, 2016	29.28	30.09	29.28	29.70	458,100	29.47
Jan 29, 2016	28.86	29.36	28.85	29.34	474,200	29.11
Jan 28, 2016	28.70	29.25	28.66	28.70	346,400	28.48
Jan 27, 2016	28.92	29.06	28.72	28.79	298,900	28.57
Jan 26, 2016	28.39	29.09	28.38	29.07	396,200	28.85
Jan 25, 2016	28.51	28.60	28.15	28.36	501,600	28.14
Jan 22, 2016	27.11	29.15	27.00	28.65	1,696,400	28.43
Jan 21, 2016	27.64	27.72	26.20	26.55	600,100	26.34
Jan 20, 2016	27.84	27.94	26.76	27.53	243,100	27.32
Jan 19, 2016	27.54	28.09	27.54	27.94	237,100	27.72
Jan 15, 2016	27.75	27.91	27.15	27.69	277,100	27.48
Jan 14, 2016	27.55	28.69	27.55	28.22	382,000	28.00
Jan 13, 2016	27.76	27.90	27.39	27.50	217,000	27.29
Jan 12, 2016	27.93	27.93	27.27	27.76	259,300	27.55
Jan 11, 2016	27.51	27.98	27.51	27.72	303,200	27.51
Jan 8, 2016	27.70	27.99	27.43	27.61	487,500	27.40
Jan 7, 2016	28.10	28.18	27.62	27.62	486,800	27.41
Jan 6, 2016	27.57	28.42	27.31	28.26	481,700	28.04
Jan 5, 2016	27.99	27.99	27.09	27.66	353,600	27.45
Jan 4, 2016	27.86	27.90	27.25	27.78	633,400	27.57

* Close price adjusted for dividends and splits.

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Currency in USD.

MARKET PRICES - ES

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	58.06	58.51	58.03	58.34	2,424,000	58.34
3/30/2016	58.65	58.81	58.26	58.39	1,193,700	58.39
3/29/2016	58.00	58.60	57.70	58.53	1,308,700	58.53
3/28/2016	58.10	58.42	57.63	57.77	681,800	57.77
3/24/2016	57.74	58.29	57.65	57.83	1,283,000	57.83
3/23/2016	57.49	58.08	57.13	57.93	1,340,800	57.93
3/22/2016	57.35	57.67	57.07	57.48	2,022,300	57.48
3/21/2016	57.10	57.82	56.74	57.35	1,653,400	57.35
3/18/2016	57.82	58.07	57.18	57.19	3,029,200	57.19
3/17/2016	57.54	58.09	57.32	57.84	2,429,700	57.84
3/16/2016	56.50	57.58	56.05	57.39	1,402,700	57.39
3/15/2016	56.73	57.35	56.46	56.75	1,985,500	56.75
3/14/2016	56.59	56.83	56.15	56.74	1,580,300	56.74
3/11/2016	56.72	57.00	56.36	56.55	1,652,000	56.55
3/10/2016	56.92	57.25	56.07	56.50	2,157,900	56.50
3/9/2016	56.59	57.16	56.40	56.87	1,648,700	56.87
3/8/2016	56.35	57.03	55.89	56.69	1,950,800	56.69
3/7/2016	55.32	56.27	55.32	56.11	2,649,600	56.11
3/4/2016	54.33	55.69	54.13	55.54	1,837,700	55.54
3/3/2016	54.44	54.66	53.59	54.63	1,185,200	54.63
3/2/2016	53.96	54.38	52.62	54.34	1,800,700	54.34
3/1/2016	54.50	54.87	53.80	54.23	2,106,500	54.23
2/29/2016	54.28	54.84	53.93	54.30	1,808,600	54.30
2/26/2016	56.42	56.47	54.75	54.77	1,570,300	54.33
2/25/2016	56.45	56.92	56.25	56.66	1,060,500	56.20
2/24/2016	55.54	56.49	55.54	56.23	1,720,300	55.77
2/23/2016	55.02	56.00	55.02	55.84	1,595,600	55.39
2/22/2016	54.83	55.51	54.66	55.34	1,283,500	54.89
2/19/2016	54.42	54.74	53.83	54.67	2,494,800	54.23
2/18/2016	53.65	54.74	53.53	54.46	1,803,900	54.02
2/17/2016	53.81	53.90	53.29	53.54	1,368,000	53.10
2/16/2016	53.85	53.98	53.12	53.86	1,781,800	53.42
2/12/2016	53.88	54.07	52.93	53.51	2,236,500	53.08
2/11/2016	54.79	55.13	53.79	53.90	2,151,300	53.46
2/10/2016	54.48	55.28	53.81	54.94	2,036,700	54.49
2/9/2016	54.00	54.90	53.84	54.69	3,068,300	54.25
2/8/2016	54.14	54.78	53.43	54.09	3,262,400	53.65
2/5/2016	54.41	54.86	53.39	54.66	3,111,400	54.22
2/4/2016	55.63	55.91	54.84	54.93	3,347,600	54.48
2/3/2016	55.47	55.97	55.34	55.72	1,939,300	55.27
2/2/2016	54.27	55.23	54.03	55.08	1,859,500	54.63
2/1/2016	53.60	54.92	53.49	54.57	2,791,300	54.13
1/29/2016	53.63	54.15	53.37	53.80	3,007,800	53.36
1/28/2016	52.19	53.52	51.76	53.09	1,850,500	52.66
1/27/2016	52.23	52.68	51.84	52.32	1,753,400	51.89
1/26/2016	51.77	52.68	51.74	52.15	1,538,600	51.73
1/25/2016	51.62	51.97	51.22	51.64	1,950,700	51.22
1/22/2016	50.63	51.63	50.16	51.58	1,836,500	51.16
1/21/2016	51.27	51.47	50.21	50.58	2,350,200	50.17
1/20/2016	52.37	52.65	50.52	51.15	3,408,700	50.73
1/19/2016	51.45	52.75	51.38	52.59	2,777,800	52.16
1/15/2016	51.30	51.72	50.82	51.39	3,195,700	50.97
1/14/2016	51.28	52.22	50.57	51.86	4,149,300	51.44
1/13/2016	51.27	51.73	51.06	51.30	2,202,100	50.88
1/12/2016	51.27	51.44	50.40	51.12	1,555,400	50.70
1/11/2016	50.91	51.32	50.58	51.03	1,097,500	50.62
1/8/2016	51.17	51.49	50.72	50.82	1,290,200	50.41
1/7/2016	50.80	51.29	50.76	51.14	2,141,700	50.72
1/6/2016	51.04	51.65	50.73	51.46	1,265,500	51.04
1/5/2016	50.85	51.43	50.01	51.35	1,087,100	50.93
1/4/2016	50.65	50.89	50.23	50.88	1,590,300	50.47

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 54.56

Eversource Energy (ES) - NYSE

57.29 **1.30(2.22%)** 2:41PM EDT - Nasdaq Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

(•) Daily
( ) Weekly
( ) Monthly
( ) Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	58.06	58.51	58.03	58.34	2,424,000	58.34
Mar 30, 2016	58.65	58.81	58.26	58.39	1,193,700	58.39
Mar 29, 2016	58.00	58.60	57.70	58.53	1,308,700	58.53
Mar 28, 2016	58.10	58.42	57.63	57.77	681,800	57.77
Mar 24, 2016	57.74	58.29	57.65	57.83	1,283,000	57.83
Mar 23, 2016	57.49	58.08	57.13	57.93	1,340,800	57.93
Mar 22, 2016	57.35	57.67	57.07	57.48	2,022,300	57.48
Mar 21, 2016	57.10	57.82	56.74	57.35	1,653,400	57.35
Mar 18, 2016	57.82	58.07	57.18	57.19	3,029,200	57.19
Mar 17, 2016	57.54	58.09	57.32	57.84	2,429,700	57.84
Mar 16, 2016	56.50	57.58	56.05	57.39	1,402,700	57.39
Mar 15, 2016	56.73	57.35	56.46	56.75	1,985,500	56.75
Mar 14, 2016	56.59	56.83	56.15	56.74	1,580,300	56.74
Mar 11, 2016	56.72	57.00	56.36	56.55	1,652,000	56.55
Mar 10, 2016	56.92	57.25	56.07	56.50	2,157,900	56.50
Mar 9, 2016	56.59	57.16	56.40	56.87	1,648,700	56.87
Mar 8, 2016	56.35	57.03	55.89	56.69	1,950,800	56.69
Mar 7, 2016	55.32	56.27	55.32	56.11	2,649,600	56.11
Mar 4, 2016	54.33	55.69	54.13	55.54	1,837,700	55.54
Mar 3, 2016	54.44	54.66	53.59	54.63	1,185,200	54.63
Mar 2, 2016	53.96	54.38	52.62	54.34	1,800,700	54.34
Mar 1, 2016	54.50	54.87	53.80	54.23	2,106,500	54.23
Feb 29, 2016	54.28	54.84	53.93	54.30	1,808,600	54.30
Feb 29, 2016	0.445 Dividend					
Feb 26, 2016	56.42	56.47	54.75	54.77	1,570,300	54.33
Feb 25, 2016	56.45	56.92	56.25	56.66	1,060,500	56.20
Feb 24, 2016	55.54	56.49	55.54	56.23	1,720,300	55.77
Feb 23, 2016	55.02	56.00	55.02	55.84	1,595,600	55.39
Feb 22, 2016	54.83	55.51	54.66	55.34	1,283,500	54.89
Feb 19, 2016	54.42	54.74	53.83	54.67	2,494,800	54.23
Feb 18, 2016	53.65	54.74	53.53	54.46	1,803,900	54.02
Feb 17, 2016	53.81	53.90	53.29	53.54	1,368,000	53.10
Feb 16, 2016	53.85	53.98	53.12	53.86	1,781,800	53.42
Feb 12, 2016	53.88	54.07	52.93	53.51	2,236,500	53.08
Feb 11, 2016	54.79	55.13	53.79	53.90	2,151,300	53.46

Feb 10, 2016	54.48	55.28	53.81	54.94	2,036,700	54.49
Feb 9, 2016	54.00	54.90	53.84	54.69	3,068,300	54.25
Feb 8, 2016	54.14	54.78	53.43	54.09	3,262,400	53.65
Feb 5, 2016	54.41	54.86	53.39	54.66	3,111,400	54.22
Feb 4, 2016	55.63	55.91	54.84	54.93	3,347,600	54.48
Feb 3, 2016	55.47	55.97	55.34	55.72	1,939,300	55.27
Feb 2, 2016	54.27	55.23	54.03	55.08	1,859,500	54.63
Feb 1, 2016	53.60	54.92	53.49	54.57	2,791,300	54.13
Jan 29, 2016	53.63	54.15	53.37	53.80	3,007,800	53.36
Jan 28, 2016	52.19	53.52	51.76	53.09	1,850,500	52.66
Jan 27, 2016	52.23	52.68	51.84	52.32	1,753,400	51.89
Jan 26, 2016	51.77	52.68	51.74	52.15	1,538,600	51.73
Jan 25, 2016	51.62	51.97	51.22	51.64	1,950,700	51.22
Jan 22, 2016	50.63	51.63	50.16	51.58	1,836,500	51.16
Jan 21, 2016	51.27	51.47	50.21	50.58	2,350,200	50.17
Jan 20, 2016	52.37	52.65	50.52	51.15	3,408,700	50.73
Jan 19, 2016	51.45	52.75	51.38	52.59	2,777,800	52.16
Jan 15, 2016	51.30	51.72	50.82	51.39	3,195,700	50.97
Jan 14, 2016	51.28	52.22	50.57	51.86	4,149,300	51.44
Jan 13, 2016	51.27	51.73	51.06	51.30	2,202,100	50.88
Jan 12, 2016	51.27	51.44	50.40	51.12	1,555,400	50.70
Jan 11, 2016	50.91	51.32	50.58	51.03	1,097,500	50.62
Jan 8, 2016	51.17	51.49	50.72	50.82	1,290,200	50.41
Jan 7, 2016	50.80	51.29	50.76	51.14	2,141,700	50.72
Jan 6, 2016	51.04	51.65	50.73	51.46	1,265,500	51.04
Jan 5, 2016	50.85	51.43	50.01	51.35	1,087,100	50.93
Jan 4, 2016	50.65	50.89	50.23	50.88	1,590,300	50.47

* Close price adjusted for dividends and splits.

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Download to Spreadsheet

Currency in USD.

MARKET PRICES - GXP

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	32.29	32.40	31.98	32.25	1,169,800	32.25
3/30/2016	32.30	32.44	32.03	32.26	810,000	32.26
3/29/2016	31.72	32.31	31.72	32.25	1,355,400	32.25
3/28/2016	31.76	31.92	31.31	31.69	941,900	31.69
3/24/2016	31.23	31.80	31.17	31.70	1,507,000	31.70
3/23/2016	31.32	31.62	31.18	31.35	1,115,000	31.35
3/22/2016	31.45	31.62	31.27	31.29	943,100	31.29
3/21/2016	31.56	31.61	31.08	31.45	1,333,000	31.45
3/18/2016	31.66	31.88	31.48	31.67	2,390,500	31.67
3/17/2016	31.26	31.77	31.19	31.65	1,582,500	31.65
3/16/2016	31.21	31.31	30.65	31.26	1,430,900	31.26
3/15/2016	31.14	31.35	30.91	31.26	1,643,600	31.26
3/14/2016	30.88	31.31	30.67	31.08	1,370,300	31.08
3/11/2016	31.00	31.40	30.82	30.96	1,444,700	30.96
3/10/2016	30.58	31.22	30.19	30.87	2,486,200	30.87
3/9/2016	30.21	30.67	30.21	30.56	1,077,500	30.56
3/8/2016	30.23	30.34	29.97	30.28	1,516,300	30.28
3/7/2016	29.77	30.24	29.60	30.13	1,161,800	30.13
3/4/2016	29.34	29.96	29.22	29.84	1,122,800	29.84
3/3/2016	29.47	29.55	29.14	29.52	1,122,900	29.52
3/2/2016	29.02	29.57	28.49	29.49	1,333,800	29.49
3/1/2016	29.48	29.61	28.92	29.13	1,163,200	29.13
2/29/2016	28.75	29.66	28.65	29.34	2,075,800	29.34
2/26/2016	29.38	29.49	28.70	28.82	2,310,900	28.82
2/25/2016	29.65	29.88	29.06	29.55	1,829,000	29.55
2/24/2016	29.04	29.44	28.97	29.16	2,209,200	28.90
2/23/2016	28.97	29.24	28.81	29.05	1,343,500	28.79
2/22/2016	29.05	29.37	28.92	29.12	723,900	28.86
2/19/2016	28.97	29.12	28.71	28.94	711,200	28.68
2/18/2016	28.56	29.05	28.51	28.97	786,900	28.71
2/17/2016	28.60	28.69	28.31	28.58	685,700	28.32
2/16/2016	28.56	28.72	28.19	28.61	675,300	28.35
2/12/2016	28.51	28.76	28.11	28.45	693,000	28.19
2/11/2016	28.84	29.07	28.47	28.55	906,200	28.29
2/10/2016	28.97	29.13	28.51	28.92	1,228,800	28.66
2/9/2016	28.73	29.10	28.58	28.95	1,236,700	28.69
2/8/2016	28.80	29.18	28.32	28.80	2,019,200	28.54
2/5/2016	28.66	29.37	28.28	28.80	2,936,600	28.54
2/4/2016	29.19	29.24	28.65	28.78	2,184,500	28.52
2/3/2016	29.13	29.65	28.89	29.23	2,371,500	28.97
2/2/2016	28.31	29.07	28.21	28.98	1,226,400	28.72
2/1/2016	27.83	28.72	27.80	28.45	1,250,800	28.19
1/29/2016	27.63	28.08	27.52	27.88	1,130,700	27.63
1/28/2016	26.86	27.53	26.73	27.43	634,200	27.18
1/27/2016	26.63	27.16	26.56	26.96	601,800	26.72
1/26/2016	26.72	27.23	26.52	26.71	1,554,400	26.47
1/25/2016	26.86	26.94	26.57	26.71	581,700	26.47
1/22/2016	26.40	26.96	26.38	26.93	845,300	26.69
1/21/2016	26.45	26.67	26.13	26.34	1,209,200	26.10
1/20/2016	27.09	27.31	25.87	26.41	1,359,300	26.17
1/19/2016	26.96	27.33	26.77	27.24	1,210,300	26.99
1/15/2016	26.91	27.08	26.30	26.82	1,803,100	26.58
1/14/2016	26.62	27.45	26.34	27.21	2,795,700	26.96
1/13/2016	26.82	27.05	26.51	26.60	1,890,900	26.36
1/12/2016	27.27	27.27	26.50	26.67	3,397,200	26.43
1/11/2016	27.15	27.39	27.08	27.29	1,159,700	27.04
1/8/2016	27.28	27.45	26.97	27.00	966,200	26.76
1/7/2016	26.97	27.48	26.97	27.24	1,165,100	26.99
1/6/2016	27.15	27.34	26.99	27.28	1,115,600	27.03
1/5/2016	27.07	27.26	26.65	27.23	1,072,100	26.98
1/4/2016	27.34	27.35	26.82	27.07	1,737,100	26.83

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 29.07

Great Plains Energy Incorporated (GXP) - NYSE ★ Watchlist Like 14

31.94 0.69(2.11%) 4:10PM EDT

Historical Prices

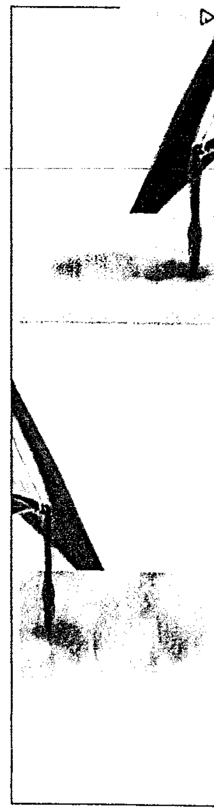
Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010
End Date: Mar 31 2016

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices



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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	32.29	32.40	31.98	32.25	1,169,800	32.25
Mar 30, 2016	32.30	32.44	32.03	32.26	810,000	32.26
Mar 29, 2016	31.72	32.31	31.72	32.25	1,355,400	32.25
Mar 28, 2016	31.76	31.92	31.31	31.69	941,900	31.69
Mar 24, 2016	31.23	31.80	31.17	31.70	1,507,000	31.70
Mar 23, 2016	31.32	31.62	31.18	31.35	1,115,000	31.35
Mar 22, 2016	31.45	31.62	31.27	31.29	943,100	31.29
Mar 21, 2016	31.56	31.61	31.08	31.45	1,346,600	31.45
Mar 18, 2016	31.66	31.88	31.48	31.67	2,441,200	31.67
Mar 17, 2016	31.26	31.77	31.19	31.65	1,582,500	31.65
Mar 16, 2016	31.21	31.31	30.65	31.26	1,432,500	31.26
Mar 15, 2016	31.14	31.35	30.91	31.26	1,643,600	31.26
Mar 14, 2016	30.88	31.31	30.67	31.08	1,370,300	31.08
Mar 11, 2016	31.00	31.40	30.82	30.96	1,444,700	30.96
Mar 10, 2016	30.58	31.22	30.19	30.87	2,486,200	30.87
Mar 9, 2016	30.21	30.67	30.21	30.56	1,077,500	30.56
Mar 8, 2016	30.23	30.34	29.97	30.28	1,516,300	30.28
Mar 7, 2016	29.77	30.24	29.60	30.13	1,161,800	30.13
Mar 4, 2016	29.34	29.96	29.22	29.84	1,122,800	29.84
Mar 3, 2016	29.47	29.55	29.14	29.52	1,122,900	29.52
Mar 2, 2016	29.02	29.57	28.49	29.49	1,333,800	29.49
Mar 1, 2016	29.48	29.61	28.92	29.13	1,163,200	29.13
Feb 29, 2016	28.75	29.66	28.65	29.34	2,075,800	29.34
Feb 26, 2016	29.38	29.49	28.70	28.82	2,310,900	28.82
Feb 25, 2016	29.65	29.88	29.06	29.55	1,829,000	29.55
Feb 25, 2016			0.263 Dividend			
Feb 24, 2016	29.04	29.44	28.97	29.16	2,209,200	28.90
Feb 23, 2016	28.97	29.24	28.81	29.05	1,343,500	28.79
Feb 22, 2016	29.05	29.37	28.92	29.12	723,900	28.86
Feb 19, 2016	28.97	29.12	28.71	28.94	711,200	28.68
Feb 18, 2016	28.56	29.05	28.51	28.97	786,900	28.71
Feb 17, 2016	28.60	28.69	28.31	28.58	685,700	28.32
Feb 16, 2016	28.56	28.72	28.19	28.61	675,300	28.35
Feb 12, 2016	28.51	28.76	28.11	28.45	693,000	28.19
Feb 11, 2016	28.84	29.07	28.47	28.55	906,200	28.29

Feb 10, 2016	28.97	29.13	28.51	28.92	1,228,800	28.66
Feb 9, 2016	28.73	29.10	28.58	28.95	1,236,700	28.69
Feb 8, 2016	28.80	29.18	28.32	28.80	2,019,200	28.54
Feb 5, 2016	28.66	29.37	28.28	28.80	2,936,600	28.54
Feb 4, 2016	29.19	29.24	28.65	28.78	2,184,500	28.52
Feb 3, 2016	29.13	29.65	28.89	29.23	2,371,500	28.97
Feb 2, 2016	28.31	29.07	28.21	28.98	1,226,400	28.72
Feb 1, 2016	27.83	28.72	27.80	28.45	1,250,800	28.19
Jan 29, 2016	27.63	28.08	27.52	27.88	1,130,700	27.63
Jan 28, 2016	26.86	27.53	26.73	27.43	634,200	27.18
Jan 27, 2016	26.63	27.16	26.56	26.96	601,800	26.72
Jan 26, 2016	26.72	27.23	26.52	26.71	1,554,400	26.47
Jan 25, 2016	26.86	26.94	26.57	26.71	581,700	26.47
Jan 22, 2016	26.40	26.96	26.38	26.93	845,300	26.69
Jan 21, 2016	26.45	26.67	26.13	26.34	1,209,200	26.10
Jan 20, 2016	27.09	27.31	25.87	26.41	1,359,300	26.17
Jan 19, 2016	26.96	27.33	26.77	27.24	1,210,300	26.99
Jan 15, 2016	26.91	27.08	26.30	26.82	1,803,100	26.58
Jan 14, 2016	26.62	27.45	26.34	27.21	2,795,700	26.96
Jan 13, 2016	26.82	27.05	26.51	26.60	1,890,900	26.36
Jan 12, 2016	27.27	27.27	26.50	26.67	3,397,200	26.43
Jan 11, 2016	27.15	27.39	27.08	27.29	1,159,700	27.04
Jan 8, 2016	27.28	27.45	26.97	27.00	966,200	26.76
Jan 7, 2016	26.97	27.48	26.97	27.24	1,165,100	26.99
Jan 6, 2016	27.15	27.34	26.99	27.28	1,115,600	27.03
Jan 5, 2016	27.07	27.26	26.65	27.23	1,072,100	26.98
Jan 4, 2016	27.34	27.35	26.82	27.07	1,737,100	26.83

* Close price adjusted for dividends and splits.

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Currency in USD.

MARKET PRICES - IDA

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	74.70	74.96	74.37	74.59	209,000	74.59
3/30/2016	74.75	74.91	74.34	74.65	245,600	74.65
3/29/2016	74.16	74.95	73.94	74.83	499,800	74.83
3/28/2016	74.27	74.56	73.56	74.00	182,200	74.00
3/24/2016	73.82	74.37	73.81	74.11	260,100	74.11
3/23/2016	74.03	74.49	73.14	74.03	221,800	74.03
3/22/2016	74.07	74.47	73.72	74.03	167,600	74.03
3/21/2016	73.05	74.29	72.44	74.17	230,300	74.17
3/18/2016	74.45	74.68	72.99	73.29	849,000	73.29
3/17/2016	73.88	74.30	73.67	74.15	527,200	74.15
3/16/2016	73.55	74.01	72.70	73.75	315,400	73.75
3/15/2016	73.18	73.96	72.88	73.55	154,800	73.55
3/14/2016	73.52	73.84	73.06	73.43	156,700	73.43
3/11/2016	74.08	74.42	73.44	73.99	179,400	73.99
3/10/2016	73.89	74.14	72.50	73.59	175,800	73.59
3/9/2016	73.36	74.07	73.36	73.83	194,100	73.83
3/8/2016	72.81	73.69	72.42	73.49	230,700	73.49
3/7/2016	71.98	72.80	71.65	72.61	218,500	72.61
3/4/2016	71.01	72.36	70.58	72.14	235,700	72.14
3/3/2016	71.20	71.46	70.49	71.44	226,600	71.44
3/2/2016	70.44	71.17	69.03	71.15	215,100	71.15
3/1/2016	71.30	71.57	69.85	70.51	297,000	70.51
2/29/2016	71.29	71.78	70.92	70.96	508,900	70.96
2/26/2016	73.10	73.27	71.05	71.29	246,700	71.29
2/25/2016	73.44	73.82	72.71	73.44	309,400	73.44
2/24/2016	72.34	73.17	71.94	73.02	288,100	73.02
2/23/2016	72.00	72.83	71.53	72.16	185,400	72.16
2/22/2016	72.05	72.57	71.67	72.19	188,600	72.19
2/19/2016	71.75	72.37	71.35	71.78	253,700	71.78
2/18/2016	69.23	71.50	68.76	71.32	306,900	71.32
2/17/2016	69.97	69.97	68.76	69.61	274,000	69.61
2/16/2016	69.94	70.53	69.14	69.84	219,500	69.84
2/12/2016	70.54	70.54	68.86	69.59	257,500	69.59
2/11/2016	70.16	70.63	69.35	70.28	288,800	70.28
2/10/2016	70.37	70.59	69.46	70.25	468,000	70.25
2/9/2016	69.37	70.54	69.03	70.48	424,700	70.48
2/8/2016	69.24	69.89	68.80	69.68	445,300	69.68
2/5/2016	69.05	70.04	68.30	69.35	309,800	69.35
2/4/2016	69.80	70.00	69.22	69.42	303,700	69.42
2/3/2016	69.37	70.16	69.11	69.87	683,500	69.87
2/2/2016	69.38	69.83	69.07	69.75	516,900	69.24
2/1/2016	69.43	69.92	69.30	69.64	894,500	69.13
1/29/2016	69.15	69.96	68.87	69.59	539,700	69.08
1/28/2016	66.96	68.77	66.85	68.46	173,000	67.96
1/27/2016	66.66	67.54	66.29	66.86	141,200	66.37
1/26/2016	66.42	67.64	66.42	66.92	131,200	66.43
1/25/2016	67.43	67.43	65.96	66.14	184,200	65.66
1/22/2016	65.88	67.49	65.54	67.47	262,000	66.98
1/21/2016	66.52	66.71	65.31	65.73	209,000	65.25
1/20/2016	67.23	67.37	65.03	66.50	273,700	66.01
1/19/2016	66.85	67.84	66.55	67.59	204,600	67.10
1/15/2016	66.46	68.42	65.40	66.49	257,900	66.00
1/14/2016	66.90	68.19	66.33	67.68	304,700	67.19
1/13/2016	67.33	67.85	66.72	66.81	201,800	66.32
1/12/2016	68.28	68.28	66.70	67.33	242,700	66.84
1/11/2016	67.28	68.15	67.28	67.96	217,700	67.46
1/8/2016	67.68	68.15	67.28	67.28	389,900	66.79
1/7/2016	66.73	67.93	66.73	67.52	326,500	67.03
1/6/2016	66.92	67.60	66.70	67.52	170,400	67.03
1/5/2016	67.29	67.57	66.26	67.41	236,300	66.92
1/4/2016	67.73	67.94	66.95	67.29	429,100	66.80

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 70.62

IdaCorp, Inc. (IDA) - NYSE

73.04 1.45(1.94%) 2:45PM EDT - Nasdaq Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	74.70	74.96	74.37	74.59	209,000	74.59
Mar 30, 2016	74.75	74.91	74.34	74.65	245,600	74.65
Mar 29, 2016	74.16	74.95	73.94	74.83	499,800	74.83
Mar 28, 2016	74.27	74.56	73.56	74.00	182,200	74.00
Mar 24, 2016	73.82	74.37	73.81	74.11	260,100	74.11
Mar 23, 2016	74.03	74.49	73.14	74.03	221,800	74.03
Mar 22, 2016	74.07	74.47	73.72	74.03	167,600	74.03
Mar 21, 2016	73.05	74.29	72.44	74.17	230,300	74.17
Mar 18, 2016	74.45	74.68	72.99	73.29	849,000	73.29
Mar 17, 2016	73.88	74.30	73.67	74.15	527,200	74.15
Mar 16, 2016	73.55	74.01	72.70	73.75	315,400	73.75
Mar 15, 2016	73.18	73.96	72.88	73.55	154,800	73.55
Mar 14, 2016	73.52	73.84	73.06	73.43	156,700	73.43
Mar 11, 2016	74.08	74.42	73.44	73.99	179,400	73.99
Mar 10, 2016	73.89	74.14	72.50	73.59	175,800	73.59
Mar 9, 2016	73.36	74.07	73.36	73.83	194,100	73.83
Mar 8, 2016	72.81	73.69	72.42	73.49	230,700	73.49
Mar 7, 2016	71.98	72.80	71.65	72.61	218,500	72.61
Mar 4, 2016	71.01	72.36	70.58	72.14	235,700	72.14
Mar 3, 2016	71.20	71.46	70.49	71.44	226,600	71.44
Mar 2, 2016	70.44	71.17	69.03	71.15	215,100	71.15
Mar 1, 2016	71.30	71.57	69.85	70.51	297,000	70.51
Feb 29, 2016	71.29	71.78	70.92	70.96	508,900	70.96
Feb 26, 2016	73.10	73.27	71.05	71.29	246,700	71.29
Feb 25, 2016	73.44	73.82	72.71	73.44	309,400	73.44
Feb 24, 2016	72.34	73.17	71.94	73.02	288,100	73.02
Feb 23, 2016	72.00	72.83	71.53	72.16	185,400	72.16
Feb 22, 2016	72.05	72.57	71.67	72.19	188,600	72.19
Feb 19, 2016	71.75	72.37	71.35	71.78	253,700	71.78
Feb 18, 2016	69.23	71.50	68.76	71.32	306,900	71.32
Feb 17, 2016	69.97	69.97	68.76	69.61	274,000	69.61
Feb 16, 2016	69.94	70.53	69.14	69.84	219,500	69.84
Feb 12, 2016	70.54	70.54	68.86	69.59	257,500	69.59
Feb 11, 2016	70.16	70.63	69.35	70.28	288,800	70.28
Feb 10, 2016	70.37	70.59	69.46	70.25	468,000	70.25

Feb 9, 2016	69.37	70.54	69.03	70.48	424,700	70.48
Feb 8, 2016	69.24	69.89	68.80	69.68	445,300	69.68
Feb 5, 2016	69.05	70.04	68.30	69.35	309,800	69.35
Feb 4, 2016	69.80	70.00	69.22	69.42	303,700	69.42
Feb 3, 2016	69.37	70.16	69.11	69.87	683,500	69.87
Feb 3, 2016			0.51 Dividend			
Feb 2, 2016	69.38	69.83	69.07	69.75	516,900	69.24
Feb 1, 2016	69.43	69.92	69.30	69.64	894,500	69.13
Jan 29, 2016	69.15	69.96	68.87	69.59	539,700	69.08
Jan 28, 2016	66.96	68.77	66.85	68.46	173,000	67.96
Jan 27, 2016	66.66	67.54	66.29	66.86	141,200	66.37
Jan 26, 2016	66.42	67.64	66.42	66.92	131,200	66.43
Jan 25, 2016	67.43	67.43	65.96	66.14	184,200	65.66
Jan 22, 2016	65.88	67.49	65.54	67.47	262,000	66.98
Jan 21, 2016	66.52	66.71	65.31	65.73	209,000	65.25
Jan 20, 2016	67.23	67.37	65.03	66.50	273,700	66.01
Jan 19, 2016	66.85	67.84	66.55	67.59	204,600	67.10
Jan 15, 2016	66.46	68.42	65.40	66.49	257,900	66.00
Jan 14, 2016	66.90	68.19	66.33	67.68	304,700	67.19
Jan 13, 2016	67.33	67.85	66.72	66.81	201,800	66.32
Jan 12, 2016	68.28	68.28	66.70	67.33	242,700	66.84
Jan 11, 2016	67.28	68.15	67.28	67.96	217,700	67.46
Jan 8, 2016	67.68	68.15	67.28	67.28	389,900	66.79
Jan 7, 2016	66.73	67.93	66.73	67.52	326,500	67.03
Jan 6, 2016	66.92	67.60	66.70	67.52	170,400	67.03
Jan 5, 2016	67.29	67.57	66.26	67.41	236,300	66.92
Jan 4, 2016	67.73	67.94	66.95	67.29	429,100	66.80

* Close price adjusted for dividends and splits.

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Currency in USD.

MARKET PRICES - OTTR

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	29.52	29.73	29.25	29.62	221,600	29.62
3/30/2016	29.37	29.61	29.23	29.33	123,400	29.33
3/29/2016	28.54	29.33	28.39	29.31	162,300	29.31
3/28/2016	28.66	28.82	28.19	28.45	68,000	28.45
3/24/2016	28.19	28.54	28.18	28.53	76,400	28.53
3/23/2016	28.21	28.48	28.09	28.16	88,500	28.16
3/22/2016	28.33	28.57	28.15	28.24	68,200	28.24
3/21/2016	28.67	28.67	28.17	28.32	88,600	28.32
3/18/2016	28.60	28.73	28.30	28.66	242,400	28.66
3/17/2016	27.92	28.54	27.90	28.42	113,000	28.42
3/16/2016	27.33	27.95	27.29	27.84	88,000	27.84
3/15/2016	27.62	27.94	27.58	27.60	61,600	27.60
3/14/2016	27.81	28.05	27.15	27.61	79,200	27.61
3/11/2016	28.15	28.33	27.75	27.96	104,000	27.96
3/10/2016	28.29	28.34	27.54	27.94	120,500	27.94
3/9/2016	28.00	28.14	27.54	28.12	112,000	28.12
3/8/2016	27.79	27.93	27.50	27.82	117,500	27.82
3/7/2016	27.24	27.87	27.23	27.80	157,900	27.80
3/4/2016	26.97	27.40	26.77	27.16	197,700	27.16
3/3/2016	27.06	27.16	26.50	27.10	130,700	27.10
3/2/2016	27.17	27.17	26.56	27.04	149,900	27.04
3/1/2016	27.50	27.65	26.68	27.14	105,000	27.14
2/29/2016	26.78	27.50	26.78	27.36	200,400	27.36
2/26/2016	27.47	27.47	26.73	26.88	98,300	26.88
2/25/2016	27.32	27.56	27.09	27.38	50,400	27.38
2/24/2016	26.94	27.37	26.92	27.31	66,000	27.31
2/23/2016	27.02	27.31	26.79	27.04	88,700	27.04
2/22/2016	27.24	27.47	26.95	27.00	70,200	27.00
2/19/2016	27.38	27.60	26.92	26.98	88,700	26.98
2/18/2016	26.82	27.46	26.66	27.34	91,700	27.34
2/17/2016	27.08	27.08	26.72	26.84	131,500	26.84
2/16/2016	26.93	27.14	26.63	26.83	84,300	26.83
2/12/2016	26.52	26.79	26.25	26.62	105,100	26.62
2/11/2016	26.09	26.78	26.09	26.43	163,600	26.43
2/10/2016	27.59	27.76	26.55	26.65	146,200	26.65
2/9/2016	27.56	28.99	27.03	27.89	178,600	27.58
2/8/2016	28.36	28.94	28.25	28.87	115,700	28.55
2/5/2016	28.56	28.80	28.00	28.39	140,100	28.07
2/4/2016	29.19	29.39	28.44	28.49	104,100	28.17
2/3/2016	28.67	29.28	28.48	29.13	135,800	28.80
2/2/2016	28.10	28.63	27.86	28.60	89,700	28.28
2/1/2016	27.80	28.51	27.76	28.29	113,400	27.97
1/29/2016	27.08	27.86	26.81	27.84	178,100	27.53
1/28/2016	26.58	27.03	26.42	26.90	190,500	26.60
1/27/2016	26.11	26.75	26.11	26.34	125,500	26.04
1/26/2016	26.31	26.72	26.31	26.43	75,100	26.13
1/25/2016	26.52	26.53	26.02	26.10	89,300	25.81
1/22/2016	26.22	26.60	26.12	26.54	160,400	26.24
1/21/2016	27.10	27.10	25.86	26.13	183,000	25.84
1/20/2016	26.83	27.37	26.10	26.90	155,200	26.60
1/19/2016	26.12	27.21	26.12	27.00	143,200	26.70
1/15/2016	26.39	26.82	25.80	26.13	156,700	25.84
1/14/2016	26.45	27.17	26.43	26.98	99,600	26.68
1/13/2016	26.84	26.92	26.30	26.39	99,600	26.09
1/12/2016	26.72	26.86	26.30	26.79	177,800	26.49
1/11/2016	26.43	26.86	26.43	26.80	93,600	26.50
1/8/2016	26.46	26.52	26.17	26.23	79,800	25.94
1/7/2016	26.32	26.67	26.32	26.42	71,400	26.12
1/6/2016	26.35	26.68	26.25	26.67	81,100	26.37
1/5/2016	26.55	26.73	26.16	26.68	49,600	26.38
1/4/2016	26.40	26.59	26.11	26.43	122,800	26.13

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 27.45

Otter Tail Corporation (OTTR) - NasdaqGS ★ Watchlist

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28.56 0.68(2.33%) 1:49PM EDT - Nasdaq Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	29.52	29.73	29.25	29.62	221,600	29.62
Mar 30, 2016	29.37	29.61	29.23	29.33	123,400	29.33
Mar 29, 2016	28.54	29.33	28.39	29.31	162,300	29.31
Mar 28, 2016	28.66	28.82	28.19	28.45	68,000	28.45
Mar 24, 2016	28.19	28.54	28.18	28.53	76,400	28.53
Mar 23, 2016	28.21	28.48	28.09	28.16	88,500	28.16
Mar 22, 2016	28.33	28.57	28.15	28.24	68,200	28.24
Mar 21, 2016	28.67	28.67	28.17	28.32	88,600	28.32
Mar 18, 2016	28.60	28.73	28.30	28.66	242,400	28.66
Mar 17, 2016	27.92	28.54	27.90	28.42	113,000	28.42
Mar 16, 2016	27.33	27.95	27.29	27.84	88,000	27.84
Mar 15, 2016	27.62	27.94	27.58	27.60	61,600	27.60
Mar 14, 2016	27.81	28.05	27.15	27.61	79,200	27.61
Mar 11, 2016	28.15	28.33	27.75	27.96	104,000	27.96
Mar 10, 2016	28.29	28.34	27.54	27.94	120,500	27.94
Mar 9, 2016	28.00	28.14	27.54	28.12	112,000	28.12
Mar 8, 2016	27.79	27.93	27.50	27.82	117,500	27.82
Mar 7, 2016	27.24	27.87	27.23	27.80	157,900	27.80
Mar 4, 2016	26.97	27.40	26.77	27.16	197,700	27.16
Mar 3, 2016	27.06	27.16	26.50	27.10	130,700	27.10
Mar 2, 2016	27.17	27.17	26.56	27.04	149,900	27.04
Mar 1, 2016	27.50	27.65	26.68	27.14	105,000	27.14
Feb 29, 2016	26.78	27.50	26.78	27.36	200,400	27.36
Feb 26, 2016	27.47	27.47	26.73	26.88	98,300	26.88
Feb 25, 2016	27.32	27.56	27.09	27.38	50,400	27.38
Feb 24, 2016	26.94	27.37	26.92	27.31	66,000	27.31
Feb 23, 2016	27.02	27.31	26.79	27.04	88,700	27.04
Feb 22, 2016	27.24	27.47	26.95	27.00	70,200	27.00
Feb 19, 2016	27.38	27.60	26.92	26.98	88,700	26.98
Feb 18, 2016	26.82	27.46	26.66	27.34	91,700	27.34
Feb 17, 2016	27.08	27.08	26.72	26.84	131,500	26.84
Feb 16, 2016	26.93	27.14	26.63	26.83	84,300	26.83
Feb 12, 2016	26.52	26.79	26.25	26.62	105,100	26.62
Feb 11, 2016	26.09	26.78	26.09	26.43	163,600	26.43
Feb 10, 2016	27.59	27.76	26.55	26.65	146,200	26.65

Feb 10, 2016			0.313 Dividend			
Feb 9, 2016	27.56	28.99	27.03	27.89	178,600	27.58
Feb 8, 2016	28.36	28.94	28.25	28.87	115,700	28.55
Feb 5, 2016	28.56	28.80	28.00	28.39	140,100	28.07
Feb 4, 2016	29.19	29.39	28.44	28.49	104,100	28.17
Feb 3, 2016	28.67	29.28	28.48	29.13	135,800	28.80
Feb 2, 2016	28.10	28.63	27.86	28.60	89,700	28.28
Feb 1, 2016	27.80	28.51	27.76	28.29	113,400	27.97
Jan 29, 2016	27.08	27.86	26.81	27.84	178,100	27.53
Jan 28, 2016	26.58	27.03	26.42	26.90	190,500	26.60
Jan 27, 2016	26.11	26.75	26.11	26.34	125,500	26.04
Jan 26, 2016	26.31	26.72	26.31	26.43	75,100	26.13
Jan 25, 2016	26.52	26.53	26.02	26.10	89,300	25.81
Jan 22, 2016	26.22	26.60	26.12	26.54	160,400	26.24
Jan 21, 2016	27.10	27.10	25.86	26.13	183,000	25.84
Jan 20, 2016	26.83	27.37	26.10	26.90	155,200	26.60
Jan 19, 2016	26.12	27.21	26.12	27.00	143,200	26.70
Jan 15, 2016	26.39	26.82	25.80	26.13	156,700	25.84
Jan 14, 2016	26.45	27.17	26.43	26.98	99,600	26.68
Jan 13, 2016	26.84	26.92	26.30	26.39	99,600	26.09
Jan 12, 2016	26.72	26.86	26.30	26.79	177,800	26.49
Jan 11, 2016	26.43	26.86	26.43	26.80	93,600	26.50
Jan 8, 2016	26.46	26.52	26.17	26.23	79,800	25.94
Jan 7, 2016	26.32	26.67	26.32	26.42	71,400	26.12
Jan 6, 2016	26.35	26.68	26.25	26.67	81,100	26.37
Jan 5, 2016	26.55	26.73	26.16	26.68	49,600	26.38
Jan 4, 2016	26.40	26.59	26.11	26.43	122,800	26.13

* Close price adjusted for dividends and splits.

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Currency in USD.

MARKET PRICES - PNM

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	33.76	33.87	33.57	33.72	441,500	33.72
3/30/2016	33.95	34.07	33.59	33.71	305,200	33.71
3/29/2016	33.28	33.87	33.22	33.86	506,900	33.86
3/28/2016	33.33	33.53	33.09	33.29	549,700	33.29
3/24/2016	32.86	33.40	32.86	33.30	698,600	33.30
3/23/2016	33.12	33.50	32.89	33.26	377,200	33.26
3/22/2016	33.35	33.51	33.04	33.12	682,100	33.12
3/21/2016	33.47	33.51	33.01	33.35	445,900	33.35
3/18/2016	33.75	33.75	33.29	33.48	1,072,900	33.48
3/17/2016	33.53	33.81	33.35	33.75	576,600	33.75
3/16/2016	33.36	33.67	32.89	33.48	488,500	33.48
3/15/2016	33.11	33.53	33.06	33.37	676,200	33.37
3/14/2016	33.23	33.35	32.99	33.24	630,300	33.24
3/11/2016	33.43	33.57	33.11	33.21	422,800	33.21
3/10/2016	33.47	33.66	32.69	33.30	578,800	33.30
3/9/2016	33.29	33.67	33.16	33.47	663,300	33.47
3/8/2016	33.06	33.54	32.90	33.31	568,500	33.31
3/7/2016	32.78	33.19	32.68	33.01	452,100	33.01
3/4/2016	32.21	32.98	32.09	32.89	631,000	32.89
3/3/2016	32.10	32.45	31.75	32.43	730,900	32.43
3/2/2016	31.91	32.10	31.30	32.07	558,100	32.07
3/1/2016	32.09	32.27	31.77	32.06	610,400	32.06
2/29/2016	32.31	32.35	31.72	31.92	682,800	31.92
2/26/2016	32.59	32.94	31.69	31.82	587,700	31.82
2/25/2016	32.88	33.34	32.84	33.26	367,000	33.26
2/24/2016	32.63	33.05	32.63	32.93	554,200	32.93
2/23/2016	32.47	32.85	32.30	32.68	362,000	32.68
2/22/2016	32.24	32.66	32.11	32.63	427,500	32.63
2/19/2016	32.31	32.53	32.10	32.24	567,000	32.24
2/18/2016	31.62	32.44	31.47	32.36	663,400	32.36
2/17/2016	31.90	31.92	31.41	31.55	982,700	31.55
2/16/2016	31.86	31.98	31.62	31.86	433,700	31.86
2/12/2016	31.80	32.18	31.42	31.71	710,200	31.71
2/11/2016	32.18	32.22	31.59	31.91	725,300	31.91
2/10/2016	32.15	32.37	31.30	32.16	1,049,400	32.16
2/9/2016	32.09	32.51	31.91	32.30	1,473,800	32.30
2/8/2016	32.12	32.49	31.87	32.23	996,000	32.23
2/5/2016	31.62	32.45	31.27	32.14	986,200	32.14
2/4/2016	31.91	32.03	31.34	31.79	859,200	31.79
2/3/2016	31.92	32.31	31.71	31.96	884,800	31.96
2/2/2016	31.55	31.95	31.40	31.79	707,100	31.79
2/1/2016	31.37	31.99	31.24	31.56	1,076,200	31.56
1/29/2016	31.01	31.41	30.96	31.41	801,000	31.41
1/28/2016	30.20	30.91	30.07	30.78	449,500	30.78
1/27/2016	29.91	30.44	29.82	30.14	425,100	30.14
1/26/2016	29.80	30.35	29.79	30.05	377,400	30.05
1/25/2016	30.11	30.20	29.60	29.64	440,500	29.64
1/22/2016	29.43	30.15	29.29	30.12	580,100	30.12
1/21/2016	29.88	30.02	29.22	29.35	872,800	29.35
1/20/2016	30.45	30.64	29.32	30.09	973,300	29.87
1/19/2016	30.31	30.81	30.24	30.55	819,800	30.33
1/15/2016	30.22	30.55	29.70	30.20	750,000	29.98
1/14/2016	30.06	30.84	29.88	30.66	866,500	30.44
1/13/2016	30.43	30.63	29.92	30.05	847,100	29.83
1/12/2016	31.04	31.04	30.04	30.43	840,800	30.21
1/11/2016	30.86	31.09	30.68	30.93	619,300	30.70
1/8/2016	30.80	31.14	30.71	30.79	926,300	30.56
1/7/2016	30.34	30.81	30.31	30.75	803,800	30.53
1/6/2016	30.39	30.75	30.24	30.69	520,200	30.47
1/5/2016	30.17	30.60	29.76	30.57	577,700	30.35
1/4/2016	30.62	30.62	29.99	30.17	965,500	29.95

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 31.98

PNM Resources, Inc. (PNM) - NYSE ★ Watchlist Like 7

32.88 0.69(2.04%) 1:59PM EDT - NYSE Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010
End Date: Mar 31 2016

(•) Daily
( ) Weekly
( ) Monthly
( ) Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	33.76	33.87	33.57	33.72	441,500	33.72
Mar 30, 2016	33.95	34.07	33.59	33.71	305,200	33.71
Mar 29, 2016	33.28	33.87	33.22	33.86	506,900	33.86
Mar 28, 2016	33.33	33.53	33.09	33.29	549,700	33.29
Mar 24, 2016	32.86	33.40	32.86	33.30	698,600	33.30
Mar 23, 2016	33.12	33.50	32.89	33.26	377,200	33.26
Mar 22, 2016	33.35	33.51	33.04	33.12	682,100	33.12
Mar 21, 2016	33.47	33.51	33.01	33.35	445,900	33.35
Mar 18, 2016	33.75	33.75	33.29	33.48	1,072,900	33.48
Mar 17, 2016	33.53	33.81	33.35	33.75	576,600	33.75
Mar 16, 2016	33.36	33.67	32.89	33.48	488,500	33.48
Mar 15, 2016	33.11	33.53	33.06	33.37	676,200	33.37
Mar 14, 2016	33.23	33.35	32.99	33.24	630,300	33.24
Mar 11, 2016	33.43	33.57	33.11	33.21	422,800	33.21
Mar 10, 2016	33.47	33.66	32.69	33.30	578,800	33.30
Mar 9, 2016	33.29	33.67	33.16	33.47	663,300	33.47
Mar 8, 2016	33.06	33.54	32.90	33.31	568,500	33.31
Mar 7, 2016	32.78	33.19	32.68	33.01	452,100	33.01
Mar 4, 2016	32.21	32.98	32.09	32.89	631,000	32.89
Mar 3, 2016	32.10	32.45	31.75	32.43	730,900	32.43
Mar 2, 2016	31.91	32.10	31.30	32.07	558,100	32.07
Mar 1, 2016	32.09	32.27	31.77	32.06	610,400	32.06
Feb 29, 2016	32.31	32.35	31.72	31.92	682,800	31.92
Feb 26, 2016	32.59	32.94	31.69	31.82	587,700	31.82
Feb 25, 2016	32.88	33.34	32.84	33.26	367,000	33.26
Feb 24, 2016	32.63	33.05	32.63	32.93	554,200	32.93
Feb 23, 2016	32.47	32.85	32.30	32.68	362,000	32.68
Feb 22, 2016	32.24	32.66	32.11	32.63	427,500	32.63
Feb 19, 2016	32.31	32.53	32.10	32.24	567,000	32.24
Feb 18, 2016	31.62	32.44	31.47	32.36	663,400	32.36
Feb 17, 2016	31.90	31.92	31.41	31.55	982,700	31.55
Feb 16, 2016	31.86	31.98	31.62	31.86	433,700	31.86
Feb 12, 2016	31.80	32.18	31.42	31.71	710,200	31.71
Feb 11, 2016	32.18	32.22	31.59	31.91	725,300	31.91
Feb 10, 2016	32.15	32.37	31.30	32.16	1,049,400	32.16

Feb 9, 2016	32.09	32.51	31.91	32.30	1,473,800	32.30
Feb 8, 2016	32.12	32.49	31.87	32.23	996,000	32.23
Feb 5, 2016	31.62	32.45	31.27	32.14	986,200	32.14
Feb 4, 2016	31.91	32.03	31.34	31.79	859,200	31.79
Feb 3, 2016	31.92	32.31	31.71	31.96	884,800	31.96
Feb 2, 2016	31.55	31.95	31.40	31.79	707,100	31.79
Feb 1, 2016	31.37	31.99	31.24	31.56	1,076,200	31.56
Jan 29, 2016	31.01	31.41	30.96	31.41	801,000	31.41
Jan 28, 2016	30.20	30.91	30.07	30.78	449,500	30.78
Jan 27, 2016	29.91	30.44	29.82	30.14	425,100	30.14
Jan 26, 2016	29.80	30.35	29.79	30.05	377,400	30.05
Jan 25, 2016	30.11	30.20	29.60	29.64	440,500	29.64
Jan 22, 2016	29.43	30.15	29.29	30.12	580,100	30.12
Jan 21, 2016	29.88	30.02	29.22	29.35	872,800	29.35
Jan 21, 2016			0.22 Dividend			
Jan 20, 2016	30.45	30.64	29.32	30.09	973,300	29.87
Jan 19, 2016	30.31	30.81	30.24	30.55	819,800	30.33
Jan 15, 2016	30.22	30.55	29.70	30.20	750,000	29.98
Jan 14, 2016	30.06	30.84	29.88	30.66	866,500	30.44
Jan 13, 2016	30.43	30.63	29.92	30.05	847,100	29.83
Jan 12, 2016	31.04	31.04	30.04	30.43	840,800	30.21
Jan 11, 2016	30.86	31.09	30.68	30.93	619,300	30.70
Jan 8, 2016	30.80	31.14	30.71	30.79	926,300	30.56
Jan 7, 2016	30.34	30.81	30.31	30.75	803,800	30.53
Jan 6, 2016	30.39	30.75	30.24	30.69	520,200	30.47
Jan 5, 2016	30.17	30.60	29.76	30.57	577,700	30.35
Jan 4, 2016	30.62	30.62	29.99	30.17	965,500	29.95

* Close price adjusted for dividends and splits.

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Currency in USD.

MARKET PRICES - PNW

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	74.68	75.15	74.49	75.07	857,600	75.07
3/30/2016	74.57	74.84	74.07	74.69	541,800	74.69
3/29/2016	73.60	74.69	73.43	74.64	628,600	74.64
3/28/2016	73.56	74.08	73.16	73.43	375,100	73.43
3/24/2016	73.04	73.70	72.72	73.49	553,400	73.49
3/23/2016	72.54	73.53	72.24	73.29	526,000	73.29
3/22/2016	72.93	73.34	72.47	72.63	779,200	72.63
3/21/2016	72.44	73.08	71.75	72.86	541,500	72.86
3/18/2016	73.53	73.53	72.59	72.70	1,649,700	72.70
3/17/2016	72.55	73.50	72.26	73.39	784,600	73.39
3/16/2016	71.55	72.62	70.85	72.51	487,700	72.51
3/15/2016	71.33	71.99	71.33	71.82	505,800	71.82
3/14/2016	71.00	71.77	70.45	71.50	848,900	71.50
3/11/2016	71.61	71.92	70.90	71.18	828,900	71.18
3/10/2016	70.74	71.81	69.91	71.37	1,779,400	71.37
3/9/2016	69.94	70.95	69.80	70.74	987,500	70.74
3/8/2016	69.36	70.28	68.96	70.12	1,022,600	70.12
3/7/2016	68.89	69.60	68.77	69.18	769,700	69.18
3/4/2016	68.08	69.33	67.80	69.00	1,049,000	69.00
3/3/2016	68.59	68.59	67.55	68.48	976,100	68.48
3/2/2016	67.72	68.50	66.35	68.49	1,098,100	68.49
3/1/2016	69.20	69.44	67.83	67.92	1,560,800	67.92
2/29/2016	68.41	69.26	67.90	68.83	1,325,100	68.83
2/26/2016	70.71	70.79	68.49	68.54	1,386,700	68.54
2/25/2016	70.55	71.40	70.12	71.21	692,000	71.21
2/24/2016	69.90	70.54	69.32	70.15	880,000	70.15
2/23/2016	69.17	70.07	68.52	69.89	675,900	69.89
2/22/2016	68.93	69.85	68.32	69.55	1,175,500	69.55
2/19/2016	67.54	68.65	66.62	68.25	1,943,200	68.25
2/18/2016	66.94	68.02	66.56	67.47	1,542,600	67.47
2/17/2016	67.18	67.18	66.22	66.83	975,700	66.83
2/16/2016	67.35	67.44	66.67	67.25	853,600	67.25
2/12/2016	67.44	67.91	66.42	67.22	908,900	67.22
2/11/2016	68.43	68.99	67.54	67.58	821,400	67.58
2/10/2016	68.35	69.25	67.51	68.75	935,000	68.75
2/9/2016	68.42	69.00	67.91	68.48	1,750,000	68.48
2/8/2016	68.98	69.72	67.64	68.49	1,629,400	68.49
2/5/2016	68.55	69.19	67.81	68.52	1,847,900	68.52
2/4/2016	69.65	69.83	68.61	68.83	1,307,800	68.83
2/3/2016	68.69	70.00	68.69	69.71	1,669,300	69.71
2/2/2016	66.97	68.46	66.66	68.28	1,187,100	68.28
2/1/2016	66.24	67.59	66.02	67.27	1,346,900	67.27
1/29/2016	65.10	66.49	65.06	66.31	1,102,200	66.31
1/28/2016	64.45	65.11	62.82	64.67	789,900	64.67
1/27/2016	63.99	64.63	63.52	64.03	655,400	63.41
1/26/2016	63.39	64.78	62.51	64.00	677,500	63.38
1/25/2016	64.13	64.31	63.50	63.75	687,600	63.13
1/22/2016	63.46	64.23	62.98	64.10	1,351,500	63.47
1/21/2016	63.90	64.17	62.72	63.26	821,700	62.64
1/20/2016	64.77	64.98	62.52	63.62	766,700	63.00
1/19/2016	64.57	65.14	63.94	64.88	744,200	64.25
1/15/2016	64.81	64.82	63.13	64.01	784,000	63.39
1/14/2016	63.84	65.28	63.64	64.81	849,900	64.18
1/13/2016	63.80	64.75	63.56	63.87	1,082,000	63.25
1/12/2016	63.10	64.56	62.85	63.70	1,492,900	63.08
1/11/2016	64.19	65.15	64.19	64.78	898,700	64.15
1/8/2016	64.51	65.02	63.93	64.02	979,900	63.40
1/7/2016	63.88	64.62	63.70	64.47	839,000	63.84
1/6/2016	63.92	64.68	63.76	64.49	644,500	63.86
1/5/2016	63.96	64.54	62.94	64.40	695,100	63.77
1/4/2016	64.31	64.49	63.45	64.08	1,045,300	63.45

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 68.37

Pinnacle West Capital Corporation (PNW) - NYSE ★ Watchlist

Like 6

74.41 0.96(1.27%) 2:46PM EDT - NYSE Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

First | Previous | Next | Last

Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	74.68	75.15	74.49	75.07	857,600	75.07
Mar 30, 2016	74.57	74.84	74.07	74.69	541,800	74.69
Mar 29, 2016	73.60	74.69	73.43	74.64	628,600	74.64
Mar 28, 2016	73.56	74.08	73.16	73.43	375,100	73.43
Mar 24, 2016	73.04	73.70	72.72	73.49	553,400	73.49
Mar 23, 2016	72.54	73.53	72.24	73.29	526,000	73.29
Mar 22, 2016	72.93	73.34	72.47	72.63	779,200	72.63
Mar 21, 2016	72.44	73.08	71.75	72.86	541,500	72.86
Mar 18, 2016	73.53	73.53	72.59	72.70	1,649,700	72.70
Mar 17, 2016	72.55	73.50	72.26	73.39	784,600	73.39
Mar 16, 2016	71.55	72.62	70.85	72.51	487,700	72.51
Mar 15, 2016	71.33	71.99	71.33	71.82	505,800	71.82
Mar 14, 2016	71.00	71.77	70.45	71.50	848,900	71.50
Mar 11, 2016	71.61	71.92	70.90	71.18	828,900	71.18
Mar 10, 2016	70.74	71.81	69.91	71.37	1,779,400	71.37
Mar 9, 2016	69.94	70.95	69.80	70.74	987,500	70.74
Mar 8, 2016	69.36	70.28	68.96	70.12	1,022,600	70.12
Mar 7, 2016	68.89	69.60	68.77	69.18	769,700	69.18
Mar 4, 2016	68.08	69.33	67.80	69.00	1,049,000	69.00
Mar 3, 2016	68.59	68.59	67.55	68.48	976,100	68.48
Mar 2, 2016	67.72	68.50	66.35	68.49	1,098,100	68.49
Mar 1, 2016	69.20	69.44	67.83	67.92	1,560,800	67.92
Feb 29, 2016	68.41	69.26	67.90	68.83	1,325,100	68.83
Feb 26, 2016	70.71	70.79	68.49	68.54	1,386,700	68.54
Feb 25, 2016	70.55	71.40	70.12	71.21	692,000	71.21
Feb 24, 2016	69.90	70.54	69.32	70.15	880,000	70.15
Feb 23, 2016	69.17	70.07	68.52	69.89	675,900	69.89
Feb 22, 2016	68.93	69.85	68.32	69.55	1,175,500	69.55
Feb 19, 2016	67.54	68.65	66.62	68.25	1,943,200	68.25
Feb 18, 2016	66.94	68.02	66.56	67.47	1,542,600	67.47
Feb 17, 2016	67.18	67.18	66.22	66.83	975,700	66.83
Feb 16, 2016	67.35	67.44	66.67	67.25	853,600	67.25
Feb 12, 2016	67.44	67.91	66.42	67.22	908,900	67.22
Feb 11, 2016	68.43	68.99	67.54	67.58	821,400	67.58
Feb 10, 2016	68.35	69.25	67.51	68.75	935,000	68.75

Feb 9, 2016	68.42	69.00	67.91	68.48	1,750,000	68.48
Feb 8, 2016	68.98	69.72	67.64	68.49	1,629,400	68.49
Feb 5, 2016	68.55	69.19	67.81	68.52	1,847,900	68.52
Feb 4, 2016	69.65	69.83	68.61	68.83	1,307,800	68.83
Feb 3, 2016	68.69	70.00	68.69	69.71	1,669,300	69.71
Feb 2, 2016	66.97	68.46	66.66	68.28	1,187,100	68.28
Feb 1, 2016	66.24	67.59	66.02	67.27	1,346,900	67.27
Jan 29, 2016	65.10	66.49	65.06	66.31	1,102,200	66.31
Jan 28, 2016	64.45	65.11	62.82	64.67	789,900	64.67
Jan 28, 2016			0.625 Dividend			
Jan 27, 2016	63.99	64.63	63.52	64.03	655,400	63.41
Jan 26, 2016	63.39	64.78	62.51	64.00	677,500	63.38
Jan 25, 2016	64.13	64.31	63.50	63.75	687,600	63.13
Jan 22, 2016	63.46	64.23	62.98	64.10	1,351,500	63.47
Jan 21, 2016	63.90	64.17	62.72	63.26	821,700	62.64
Jan 20, 2016	64.77	64.98	62.52	63.62	766,700	63.00
Jan 19, 2016	64.57	65.14	63.94	64.88	744,200	64.25
Jan 15, 2016	64.81	64.82	63.13	64.01	784,000	63.39
Jan 14, 2016	63.84	65.28	63.64	64.81	849,900	64.18
Jan 13, 2016	63.80	64.75	63.56	63.87	1,082,000	63.25
Jan 12, 2016	63.10	64.56	62.85	63.70	1,492,900	63.08
Jan 11, 2016	64.19	65.15	64.19	64.78	898,700	64.15
Jan 8, 2016	64.51	65.02	63.93	64.02	979,900	63.40
Jan 7, 2016	63.88	64.62	63.70	64.47	839,000	63.84
Jan 6, 2016	63.92	64.68	63.76	64.49	644,500	63.86
Jan 5, 2016	63.96	64.54	62.94	64.40	695,100	63.77
Jan 4, 2016	64.31	64.49	63.45	64.08	1,045,300	63.45

* Close price adjusted for dividends and splits.

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Currency in USD.

MARKET PRICES - POR

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	39.40	39.63	39.22	39.49	1,120,500	39.49
3/30/2016	39.69	39.69	39.25	39.35	511,800	39.35
3/29/2016	39.22	39.64	39.04	39.58	1,055,300	39.58
3/28/2016	39.27	39.57	38.84	39.04	743,200	39.04
3/24/2016	39.35	39.61	39.05	39.32	800,200	39.32
3/23/2016	38.99	39.63	38.69	39.50	530,900	39.50
3/22/2016	38.05	39.23	38.05	38.99	569,200	38.99
3/21/2016	39.42	39.55	38.92	39.46	510,600	39.16
3/18/2016	39.90	39.90	39.26	39.55	771,100	39.25
3/17/2016	39.24	39.87	39.03	39.78	740,100	39.48
3/16/2016	38.85	39.31	38.39	39.24	536,200	38.94
3/15/2016	38.70	39.20	38.55	38.90	459,100	38.60
3/14/2016	39.23	39.48	38.76	38.82	379,000	38.52
3/11/2016	39.18	39.39	38.89	39.24	522,100	38.94
3/10/2016	38.92	39.08	38.30	38.99	674,400	38.69
3/9/2016	38.67	39.08	38.56	38.87	775,200	38.57
3/8/2016	37.94	38.86	37.71	38.76	785,500	38.47
3/7/2016	37.69	37.91	37.51	37.91	980,800	37.62
3/4/2016	37.95	37.95	37.34	37.82	1,261,100	37.53
3/3/2016	37.63	38.19	37.20	38.18	858,600	37.89
3/2/2016	37.60	37.62	37.04	37.51	1,185,800	37.22
3/1/2016	38.22	38.41	37.54	37.70	470,900	37.41
2/29/2016	37.90	38.47	37.76	38.05	596,200	37.76
2/26/2016	39.08	39.18	37.94	37.95	580,500	37.66
2/25/2016	38.95	39.38	38.87	39.35	453,300	39.05
2/24/2016	38.54	39.00	38.51	38.92	473,000	38.62
2/23/2016	38.21	38.64	38.02	38.56	685,200	38.27
2/22/2016	38.12	38.89	38.04	38.45	969,500	38.16
2/19/2016	37.94	38.09	37.61	37.88	1,019,100	37.59
2/18/2016	37.62	38.10	37.40	37.99	2,181,500	37.70
2/17/2016	37.85	38.13	37.51	37.57	1,442,500	37.28
2/16/2016	37.83	38.27	37.61	37.84	1,346,400	37.55
2/12/2016	39.28	39.28	37.83	38.22	1,294,400	37.93
2/11/2016	39.41	39.62	38.98	39.02	1,245,500	38.72
2/10/2016	39.95	40.11	39.05	39.55	1,814,900	39.25
2/9/2016	39.97	40.30	39.88	39.92	1,136,400	39.62
2/8/2016	40.18	40.41	39.26	39.95	1,140,900	39.65
2/5/2016	39.70	40.42	39.31	40.23	765,900	39.92
2/4/2016	40.11	40.44	39.79	39.90	685,200	39.60
2/3/2016	40.15	40.48	39.79	40.29	1,040,700	39.98
2/2/2016	39.24	40.15	39.15	39.97	925,100	39.67
2/1/2016	38.54	39.76	38.28	39.43	1,107,900	39.13
1/29/2016	38.40	39.02	38.25	38.87	728,600	38.57
1/28/2016	37.45	38.35	37.01	38.11	689,500	37.82
1/27/2016	37.25	37.79	37.11	37.59	792,200	37.30
1/26/2016	37.14	37.76	37.14	37.42	760,800	37.14
1/25/2016	37.60	37.71	36.90	37.01	830,000	36.73
1/22/2016	36.59	37.66	36.59	37.66	1,154,400	37.37
1/21/2016	36.84	37.00	36.21	36.58	1,618,900	36.30
1/20/2016	37.40	37.74	36.23	36.83	1,207,400	36.55
1/19/2016	36.92	37.85	36.77	37.69	1,181,000	37.40
1/15/2016	36.45	36.91	36.03	36.74	1,205,400	36.46
1/14/2016	36.76	37.57	36.29	37.39	1,238,800	37.11
1/13/2016	36.20	36.95	36.18	36.55	1,355,800	36.27
1/12/2016	36.69	36.69	35.44	36.20	799,700	35.92
1/11/2016	36.04	36.39	35.93	36.31	649,300	36.03
1/8/2016	36.03	36.33	35.86	35.94	962,900	35.67
1/7/2016	35.60	35.98	35.50	35.91	1,138,600	35.64
1/6/2016	35.70	36.04	35.64	36.03	923,800	35.76
1/5/2016	35.86	36.09	35.27	35.99	564,500	35.72
1/4/2016	35.52	36.19	35.49	35.80	1,175,000	35.53

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 38.29

Portland General Electric Company (POR) - NYSE ★ Watchlist Like 11

39.41 0.59(1.48%) 2:46PM EDT - NYSE Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010
End Date: Mar 31 2016

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	39.40	39.63	39.22	39.49	1,120,500	39.49
Mar 30, 2016	39.69	39.69	39.25	39.35	511,800	39.35
Mar 29, 2016	39.22	39.64	39.04	39.58	1,055,300	39.58
Mar 28, 2016	39.27	39.57	38.84	39.04	743,200	39.04
Mar 24, 2016	39.35	39.61	39.05	39.32	800,200	39.32
Mar 23, 2016	38.99	39.63	38.69	39.50	530,900	39.50
Mar 22, 2016	38.05	39.23	38.05	38.99	569,200	38.99
Mar 22, 2016	0.30 Dividend					
Mar 21, 2016	39.42	39.55	38.92	39.46	510,600	39.16
Mar 18, 2016	39.90	39.90	39.26	39.55	771,100	39.25
Mar 17, 2016	39.24	39.87	39.03	39.78	740,100	39.48
Mar 16, 2016	38.85	39.31	38.39	39.24	536,200	38.94
Mar 15, 2016	38.70	39.20	38.55	38.90	459,100	38.60
Mar 14, 2016	39.23	39.48	38.76	38.82	379,000	38.52
Mar 11, 2016	39.18	39.39	38.89	39.24	522,100	38.94
Mar 10, 2016	36.92	39.08	38.30	38.99	674,400	38.69
Mar 9, 2016	38.67	39.08	38.56	38.87	775,200	38.57
Mar 8, 2016	37.94	38.86	37.71	38.76	785,500	38.47
Mar 7, 2016	37.69	37.91	37.51	37.91	980,800	37.62
Mar 4, 2016	37.95	37.95	37.34	37.82	1,261,100	37.53
Mar 3, 2016	37.63	38.19	37.20	38.18	858,600	37.89
Mar 2, 2016	37.60	37.62	37.04	37.51	1,185,800	37.22
Mar 1, 2016	38.22	38.41	37.54	37.70	470,900	37.41
Feb 29, 2016	37.90	38.47	37.76	38.05	596,200	37.76
Feb 26, 2016	39.08	39.18	37.94	37.95	580,500	37.66
Feb 25, 2016	38.95	39.38	38.87	39.35	453,300	39.05
Feb 24, 2016	38.54	39.00	38.51	38.92	473,000	38.62
Feb 23, 2016	38.21	38.64	38.02	38.56	685,200	38.27
Feb 22, 2016	38.12	38.89	38.04	38.45	969,500	38.16
Feb 19, 2016	37.94	38.09	37.61	37.88	1,019,100	37.59
Feb 18, 2016	37.62	38.10	37.40	37.99	2,181,500	37.70
Feb 17, 2016	37.85	38.13	37.51	37.57	1,442,500	37.28
Feb 16, 2016	37.83	38.27	37.61	37.84	1,346,400	37.55
Feb 12, 2016	39.28	39.28	37.83	38.22	1,294,400	37.93
Feb 11, 2016	39.41	39.62	38.98	39.02	1,245,500	38.72

Feb 10, 2016	39.95	40.11	39.05	39.55	1,814,900	39.25
Feb 9, 2016	39.97	40.30	39.88	39.92	1,136,400	39.62
Feb 8, 2016	40.18	40.41	39.26	39.95	1,140,900	39.65
Feb 5, 2016	39.70	40.42	39.31	40.23	765,900	39.92
Feb 4, 2016	40.11	40.44	39.79	39.90	685,200	39.60
Feb 3, 2016	40.15	40.48	39.79	40.29	1,040,700	39.98
Feb 2, 2016	39.24	40.15	39.15	39.97	925,100	39.67
Feb 1, 2016	38.54	39.76	38.28	39.43	1,107,900	39.13
Jan 29, 2016	38.40	39.02	38.25	38.87	728,600	38.57
Jan 28, 2016	37.45	38.35	37.01	38.11	689,500	37.82
Jan 27, 2016	37.25	37.79	37.11	37.59	792,200	37.30
Jan 26, 2016	37.14	37.76	37.14	37.42	760,800	37.14
Jan 25, 2016	37.60	37.71	36.90	37.01	830,000	36.73
Jan 22, 2016	36.59	37.66	36.59	37.66	1,154,400	37.37
Jan 21, 2016	36.84	37.00	36.21	36.58	1,618,900	36.30
Jan 20, 2016	37.40	37.74	36.23	36.83	1,207,400	36.55
Jan 19, 2016	36.92	37.85	36.77	37.69	1,181,000	37.40
Jan 15, 2016	36.45	36.91	36.03	36.74	1,205,400	36.46
Jan 14, 2016	36.76	37.57	36.29	37.39	1,238,800	37.11
Jan 13, 2016	36.20	36.95	36.18	36.55	1,355,800	36.27
Jan 12, 2016	36.69	36.69	35.44	36.20	799,700	35.92
Jan 11, 2016	36.04	36.39	35.93	36.31	649,300	36.03
Jan 8, 2016	36.03	36.33	35.86	35.94	962,900	35.67
Jan 7, 2016	35.60	35.98	35.50	35.91	1,138,600	35.64
Jan 6, 2016	35.70	36.04	35.64	36.03	923,800	35.76
Jan 5, 2016	35.86	36.09	35.27	35.99	564,500	35.72
Jan 4, 2016	35.52	36.19	35.49	35.80	1,175,000	35.53

* Close price adjusted for dividends and splits.

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Download to Spreadsheet

Currency in USD.

MARKET PRICES - WR

Date	Open	High	Low	Close	Volume	Adj Close
3/31/2016	49.94	50.38	49.51	49.61	1,082,000	49.61
3/30/2016	50.14	50.14	49.30	49.80	989,300	49.80
3/29/2016	48.49	49.94	48.23	49.91	1,996,400	49.91
3/28/2016	48.36	48.49	47.70	48.25	978,100	48.25
3/24/2016	47.88	48.37	47.52	48.30	872,100	48.30
3/23/2016	47.72	48.00	47.19	47.82	746,800	47.82
3/22/2016	47.70	48.38	47.31	47.84	675,900	47.84
3/21/2016	48.06	48.25	47.23	47.77	679,700	47.77
3/18/2016	47.97	48.53	47.55	48.33	1,484,400	48.33
3/17/2016	47.97	48.36	47.72	48.14	857,200	48.14
3/16/2016	47.01	47.97	46.95	47.82	1,203,500	47.82
3/15/2016	46.81	47.63	46.65	47.36	862,200	47.36
3/14/2016	46.20	46.96	46.14	46.85	1,425,300	46.85
3/11/2016	46.90	48.28	46.38	46.43	3,025,200	46.43
3/10/2016	44.01	48.44	43.39	46.90	6,977,900	46.90
3/9/2016	43.58	44.16	43.58	44.08	710,800	44.08
3/8/2016	43.67	43.90	43.28	43.69	741,600	43.69
3/7/2016	42.92	43.64	42.67	43.53	991,700	43.53
3/4/2016	42.85	43.39	42.66	43.29	1,594,300	42.91
3/3/2016	42.79	43.21	42.33	43.15	1,033,200	42.77
3/2/2016	42.50	42.70	41.89	42.70	1,911,200	42.33
3/1/2016	43.74	43.80	42.53	42.71	1,317,900	42.34
2/29/2016	43.06	43.85	42.96	43.46	1,815,100	43.08
2/26/2016	44.32	44.44	43.00	43.13	2,895,400	42.75
2/25/2016	46.05	46.66	44.19	44.88	3,209,000	44.49
2/24/2016	46.12	46.67	45.94	46.35	1,307,900	45.94
2/23/2016	45.81	46.41	45.77	46.05	743,100	45.65
2/22/2016	45.77	46.15	45.48	46.07	796,900	45.67
2/19/2016	45.69	45.83	45.26	45.56	528,800	45.16
2/18/2016	45.15	45.87	44.95	45.72	772,100	45.32
2/17/2016	45.27	45.28	44.69	45.15	564,300	44.75
2/16/2016	45.00	45.37	44.53	45.27	540,700	44.87
2/12/2016	45.34	45.43	44.16	44.76	1,055,900	44.37
2/11/2016	45.30	45.53	45.02	45.22	1,725,100	44.82
2/10/2016	44.92	45.60	44.49	45.47	1,303,600	45.07
2/9/2016	44.68	45.20	44.47	44.99	756,000	44.60
2/8/2016	45.12	45.69	44.23	44.78	1,358,700	44.39
2/5/2016	45.07	45.97	44.50	45.26	1,940,800	44.86
2/4/2016	45.78	46.14	45.04	45.14	1,767,700	44.74
2/3/2016	45.25	46.60	45.25	45.96	2,502,700	45.56
2/2/2016	44.17	45.36	44.12	44.99	1,588,000	44.60
2/1/2016	43.42	44.61	43.33	44.28	1,530,300	43.89
1/29/2016	42.53	43.59	42.50	43.56	1,143,300	43.18
1/28/2016	41.54	42.36	41.33	42.23	508,100	41.86
1/27/2016	41.23	41.88	41.11	41.48	612,100	41.12
1/26/2016	41.15	41.82	41.07	41.37	535,800	41.01
1/25/2016	41.45	41.65	40.92	41.02	680,200	40.66
1/22/2016	40.56	41.66	40.35	41.66	1,226,800	41.29
1/21/2016	40.73	41.00	40.22	40.38	1,086,700	40.03
1/20/2016	41.44	41.76	40.01	40.71	846,700	40.35
1/19/2016	41.38	41.93	41.24	41.71	1,251,400	41.34
1/15/2016	41.45	41.84	40.55	41.20	1,434,700	40.84
1/14/2016	41.59	42.25	41.16	41.94	940,300	41.57
1/13/2016	41.73	42.07	41.47	41.58	1,343,300	41.22
1/12/2016	42.39	42.45	41.33	41.55	1,851,900	41.19
1/11/2016	42.17	42.60	42.05	42.25	884,200	41.88
1/8/2016	42.44	42.65	41.96	42.09	897,000	41.72
1/7/2016	42.25	42.76	42.05	42.24	1,382,800	41.87
1/6/2016	42.35	42.80	42.06	42.74	936,300	42.36
1/5/2016	42.37	42.76	41.81	42.64	561,200	42.27
1/4/2016	42.11	42.40	41.98	42.37	756,700	42.00

AVERAGE STOCK PRICE FOR THREE MONTH PERIOD

$ 44.61

WR

Westar Energy, Inc. (WR) - NYSE

49.37 **0.77(1.54%)** 2:07PM EDT - Nasdaq Real Time Price

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jan 1 2016 Eg. Jan 1, 2010

End Date: Mar 31 2016

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Mar 31, 2016	49.94	50.38	49.51	49.61	1,082,000	49.61
Mar 30, 2016	50.14	50.14	49.30	49.80	989,300	49.80
Mar 29, 2016	48.49	49.94	48.23	49.91	1,996,400	49.91
Mar 28, 2016	48.36	48.49	47.70	48.25	978,100	48.25
Mar 24, 2016	47.88	48.37	47.52	48.30	872,100	48.30
Mar 23, 2016	47.72	48.00	47.19	47.82	746,800	47.82
Mar 22, 2016	47.70	48.38	47.31	47.84	675,900	47.84
Mar 21, 2016	48.06	48.25	47.23	47.77	679,700	47.77
Mar 18, 2016	47.97	48.53	47.55	48.33	1,484,400	48.33
Mar 17, 2016	47.97	48.36	47.72	48.14	857,200	48.14
Mar 16, 2016	47.01	47.97	46.95	47.82	1,203,500	47.82
Mar 15, 2016	46.81	47.63	46.65	47.36	862,200	47.36
Mar 14, 2016	46.20	46.96	46.14	46.85	1,425,300	46.85
Mar 11, 2016	46.90	48.28	46.38	46.43	3,025,200	46.43
Mar 10, 2016	44.01	48.44	43.39	46.90	6,977,900	46.90
Mar 9, 2016	43.58	44.16	43.58	44.08	710,800	44.08
Mar 8, 2016	43.67	43.90	43.28	43.69	741,600	43.69
Mar 7, 2016	42.92	43.64	42.67	43.53	991,700	43.53
Mar 7, 2016			0.38 Dividend			
Mar 4, 2016	42.85	43.39	42.66	43.29	1,594,300	42.91
Mar 3, 2016	42.79	43.21	42.33	43.15	1,033,200	42.77
Mar 2, 2016	42.50	42.70	41.89	42.70	1,911,200	42.33
Mar 1, 2016	43.74	43.80	42.53	42.71	1,317,900	42.34
Feb 29, 2016	43.06	43.85	42.96	43.46	1,815,100	43.08
Feb 26, 2016	44.32	44.44	43.00	43.13	2,895,400	42.75
Feb 25, 2016	46.05	46.66	44.19	44.88	3,209,000	44.49
Feb 24, 2016	46.12	46.67	45.94	46.35	1,307,900	45.94
Feb 23, 2016	45.81	46.41	45.77	46.05	743,100	45.65
Feb 22, 2016	45.77	46.15	45.48	46.07	796,900	45.67
Feb 19, 2016	45.69	45.83	45.26	45.56	528,800	45.16
Feb 18, 2016	45.15	45.87	44.95	45.72	772,100	45.32
Feb 17, 2016	45.27	45.28	44.69	45.15	564,300	44.75
Feb 16, 2016	45.00	45.37	44.53	45.27	540,700	44.87
Feb 12, 2016	45.34	45.43	44.16	44.76	1,055,900	44.37
Feb 11, 2016	45.30	45.53	45.02	45.22	1,725,100	44.82

Feb 10, 2016	44.92	45.60	44.49	45.47	1,303,600	45.07
Feb 9, 2016	44.68	45.20	44.47	44.99	756,000	44.60
Feb 8, 2016	45.12	45.69	44.23	44.78	1,358,700	44.39
Feb 5, 2016	45.07	45.97	44.50	45.26	1,940,800	44.86
Feb 4, 2016	45.78	46.14	45.04	45.14	1,767,700	44.74
Feb 3, 2016	45.25	46.60	45.25	45.96	2,502,700	45.56
Feb 2, 2016	44.17	45.36	44.12	44.99	1,588,000	44.60
Feb 1, 2016	43.42	44.61	43.33	44.28	1,530,300	43.89
Jan 29, 2016	42.53	43.59	42.50	43.56	1,143,300	43.18
Jan 28, 2016	41.54	42.36	41.33	42.23	508,100	41.86
Jan 27, 2016	41.23	41.88	41.11	41.48	612,100	41.12
Jan 26, 2016	41.15	41.82	41.07	41.37	535,800	41.01
Jan 25, 2016	41.45	41.65	40.92	41.02	680,200	40.66
Jan 22, 2016	40.56	41.66	40.35	41.66	1,226,800	41.29
Jan 21, 2016	40.73	41.00	40.22	40.38	1,086,700	40.03
Jan 20, 2016	41.44	41.76	40.01	40.71	846,700	40.35
Jan 19, 2016	41.38	41.93	41.24	41.71	1,251,400	41.34
Jan 15, 2016	41.45	41.84	40.55	41.20	1,434,700	40.84
Jan 14, 2016	41.59	42.25	41.16	41.94	940,300	41.57
Jan 13, 2016	41.73	42.07	41.47	41.58	1,343,300	41.22
Jan 12, 2016	42.39	42.45	41.33	41.55	1,851,900	41.19
Jan 11, 2016	42.17	42.60	42.05	42.25	884,200	41.88
Jan 8, 2016	42.44	42.65	41.96	42.09	897,000	41.72
Jan 7, 2016	42.25	42.76	42.05	42.24	1,382,800	41.87
Jan 6, 2016	42.35	42.80	42.06	42.74	936,300	42.36
Jan 5, 2016	42.37	42.76	41.81	42.64	561,200	42.27
Jan 4, 2016	42.11	42.40	41.98	42.37	756,700	42.00

* Close price adjusted for dividends and splits.

First | Previous | Next | Last

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Currency in USD.

EXHIBIT 3

ALLETE, Inc. (ALE) - NYSE ★ Watchlist

55.49 0.04(0.07%) 11:32AM EDT - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.45	1.00	3.18	3.48
No. of Analysts	1.00	1.00	4.00	5.00
Low Estimate	0.45	1.00	3.15	3.40
High Estimate	0.45	1.00	3.25	3.56
Year Ago EPS	0.48	1.25	3.06	3.18

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	326.70M	358.40M	1.35B	1.38B
No. of Analysts	1	1	3	4
Low Estimate	326.70M	358.40M	1.25B	1.30B
High Estimate	326.70M	358.40M	1.50B	1.53B
Year Ago Sales	323.30M	462.50M	1.49B	1.35B
Sales Growth (year/est)	1.10%	-22.50%	-8.90%	1.50%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.50	1.02	0.78	0.90
EPS Actual	0.48	1.25	0.41	0.93
Difference	-0.02	0.23	-0.37	0.03
Surprise %	-4.00%	22.50%	-47.40%	3.30%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.45	1.00	3.18	3.48
7 Days Ago	0.45	1.00	3.18	3.48
30 Days Ago	0.52	1.06	3.29	3.56
60 Days Ago	0.52	1.06	3.31	3.59
90 Days Ago	0.51	1.06	3.31	3.59

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ALE	Industry	Sector	S&P 500
Current Qtr.	-6.20%	-3.40%	-37.00%	7.70%
Next Qtr.	-20.00%	14.30%	-39.60%	15.40%
This Year	3.90%	1.50%	21.10%	0.40%
Next Year	9.40%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	6.19%	N/A	N/A	N/A
Next 5 Years (per annum)	3.00%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	17.91	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	5.97	3.52	3.48	1.36

Currency in USD.

American Electric Power Co., Inc. (AEP) - NYSE ★ Watchlist

64.31 0.20(0.31%) 11:37AM EDT - Nasdaq Real Time Price

Analyst Estimates

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.88	1.10	3.67	3.85
No. of Analysts	11.00	11.00	22.00	22.00
Low Estimate	0.78	0.88	3.54	3.65
High Estimate	0.98	1.25	3.74	4.00
Year Ago EPS	0.88	1.06	3.69	3.67

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	4.07B	4.51B	16.84B	17.37B
No. of Analysts	6	6	14	13
Low Estimate	3.79B	4.22B	15.79B	15.17B
High Estimate	4.62B	4.86B	18.56B	19.88B
Year Ago Sales	3.90B	4.40B	16.45B	16.84B
Sales Growth (year/est)	4.40%	2.40%	2.30%	3.10%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.81	1.01	0.50	1.04
EPS Actual	0.88	1.06	0.48	1.02
Difference	0.07	0.05	-0.02	-0.02
Surprise %	8.60%	5.00%	-4.00%	-1.90%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.88	1.10	3.67	3.85
7 Days Ago	0.88	1.09	3.67	3.85
30 Days Ago	0.86	1.08	3.70	3.90
60 Days Ago	0.85	1.07	3.70	3.91
90 Days Ago	0.85	1.06	3.69	3.90

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	1
Up Last 30 Days	5	5	3	2
Down Last 30 Days	0	1	1	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	AEP	Industry	Sector	S&P 500
Current Qtr.	0.00%	-3.40%	-37.00%	7.70%
Next Qtr.	3.80%	14.30%	-39.60%	15.40%
This Year	-0.50%	1.50%	21.10%	0.40%
Next Year	4.90%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	2.90%	N/A	N/A	N/A
Next 5 Years (per annum)	4.07%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	17.89	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	4.40	3.52	3.48	1.36

Currency in USD.

EE

El Paso Electric Co. (EE) - NYSE ★ Watchlist

44.04 0.04(0.09%) 11:28AM EDT - Nasdaq Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.80	1.65	2.50	2.64
No. of Analysts	1.00	1.00	3.00	4.00
Low Estimate	0.80	1.65	2.45	2.55
High Estimate	0.80	1.65	2.56	2.70
Year Ago EPS	0.52	1.40	2.03	2.50

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	NaN	NaN	937.55M	954.60M
No. of Analysts			2	2
Low Estimate	NaN	NaN	935.30M	951.90M
High Estimate	NaN	NaN	939.80M	957.30M
Year Ago Sales	NaN	NaN	607.92M	937.55M
Sales Growth (year/est)	N/A	N/A	54.20%	1.80%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.60	1.20	0.00	-0.07
EPS Actual	0.52	1.40	0.02	-0.14
Difference	-0.08	0.20	0.02	-0.07
Surprise %	-13.30%	16.70%	N/A	-100.00%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.80	1.65	2.50	2.64
7 Days Ago	0.80	1.65	2.50	2.64
30 Days Ago	0.80	1.60	2.52	2.64
60 Days Ago	0.80	1.60	2.52	2.62
90 Days Ago	0.83	1.50	2.55	2.66

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	1	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EE	Industry	Sector	S&P 500
Current Qtr.	53.80%	-3.40%	-37.00%	7.70%
Next Qtr.	17.90%	14.30%	-39.60%	15.40%
This Year	23.20%	1.50%	21.10%	0.40%
Next Year	5.60%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	-10.03%	N/A	N/A	N/A
Next 5 Years (per annum)	7.00%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	18.21	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	2.60	3.52	3.48	1.36

Currency in USD.

The Empire District Electric Company (EDE) - NYSE ★ Watchlist Like 10

33.60 0.22(0.66%) 11:38AM EDT - Nasdaq Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	N/A	N/A	1.47	1.56
No. of Analysts	N/A	N/A	3.00	4.00
Low Estimate	N/A	N/A	1.45	1.42
High Estimate	N/A	N/A	1.51	1.65
Year Ago EPS	0.15	0.58	1.29	1.47

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	139.56M	169.71M	675.70M	681.12M
No. of Analysts	1	1	1	3
Low Estimate	139.56M	169.71M	675.70M	653.76M
High Estimate	139.56M	169.71M	675.70M	697.90M
Year Ago Sales	134.50M	169.71M	416.20M	675.70M
Sales Growth (year/est)	3.80%	0.00%	62.30%	0.80%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.24	0.59	0.28	0.30
EPS Actual	0.15	0.58	0.23	0.38
Difference	-0.09	-0.01	-0.05	0.08
Surprise %	-37.50%	-1.70%	-17.90%	26.70%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	N/A	N/A	1.47	1.56
7 Days Ago	0.08	0.70	1.47	1.56
30 Days Ago	0.20	0.60	1.48	1.58
60 Days Ago	0.20	0.60	1.48	1.58
90 Days Ago	0.20	0.60	1.48	1.58

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EDE	Industry	Sector	S&P 500
Current Qtr.	N/A	1,476.90%	-37.00%	7.70%
Next Qtr.	N/A	124.60%	-39.60%	15.40%
This Year	14.00%	11.70%	21.10%	0.40%
Next Year	6.10%	22.80%	30.40%	12.90%
Past 5 Years (per annum)	2.12%	N/A	N/A	N/A
Next 5 Years (per annum)	5.00%	7.20%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	22.85	16.19	16.14	15.34
PEG Ratio (avg. for comparison categories)	4.57	8.06	3.48	1.36

Currency in USD.

Eversource Energy (ES) - NYSE ★ Watchlist Like 14

55.95 0.13(0.23%) 11:39AM EDT - Nasdaq Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.65	0.80	2.99	3.19
No. of Analysts	10.00	10.00	18.00	17.00
Low Estimate	0.60	0.75	2.95	3.10
High Estimate	0.75	0.85	3.05	3.28
Year Ago EPS	0.66	0.75	2.81	2.99

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	1.69B	2.06B	8.09B	8.30B
No. of Analysts	2	2	9	9
Low Estimate	1.61B	2.02B	7.89B	7.92B
High Estimate	1.78B	2.11B	8.41B	8.79B
Year Ago Sales	1.87B	1.93B	7.95B	8.09B
Sales Growth (year/est)	-9.40%	6.70%	1.60%	2.60%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.56	0.76	0.62	0.78
EPS Actual	0.66	0.75	0.60	0.77
Difference	0.10	-0.01	-0.02	-0.01
Surprise %	17.90%	-1.30%	-3.20%	-1.30%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.65	0.80	2.99	3.19
7 Days Ago	0.66	0.79	2.99	3.19
30 Days Ago	0.63	0.78	3.00	3.18
60 Days Ago	0.62	0.77	3.01	3.18
90 Days Ago	0.63	0.78	3.01	3.18

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	3	2	1	2
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ES	Industry	Sector	S&P 500
Current Qtr.	-1.50%	-3.40%	-37.00%	7.70%
Next Qtr.	6.70%	14.30%	-39.60%	15.40%
This Year	6.40%	1.50%	21.10%	0.40%
Next Year	6.70%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	5.74%	N/A	N/A	N/A
Next 5 Years (per annum)	6.02%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	18.67	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	3.10	3.52	3.48	1.36

Currency in USD.

Great Plains Energy Incorporated (GXP) - NYSE ★ Watchlist Like 14

31.17 0.03(0.10%) 11:40AM EDT - Nasdaq Real Time Price

Analyst Estimates

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Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.38	1.07	1.73	1.83
No. of Analysts	5.00	4.00	9.00	13.00
Low Estimate	0.35	1.04	1.70	1.79
High Estimate	0.41	1.13	1.75	1.88
Year Ago EPS	0.28	0.82	1.37	1.73

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	632.76M	815.65M	2.60B	2.70B
No. of Analysts	3	3	7	10
Low Estimate	619.20M	776.00M	2.54B	2.59B
High Estimate	651.09M	865.95M	2.68B	2.86B
Year Ago Sales	609.00M	781.40M	2.50B	2.60B
Sales Growth (year/est)	3.90%	4.40%	4.10%	3.80%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.30	0.88	0.17	0.14
EPS Actual	0.28	0.82	0.15	0.17
Difference	-0.02	-0.06	-0.02	0.03
Surprise %	-6.70%	-6.80%	-11.80%	21.40%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.38	1.07	1.73	1.83
7 Days Ago	0.39	1.02	1.72	1.82
30 Days Ago	0.35	1.03	1.74	1.83
60 Days Ago	0.36	0.93	1.74	1.83
90 Days Ago	0.36	0.90	1.75	1.84

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	1	1
Up Last 30 Days	3	2	1	3
Down Last 30 Days	0	1	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	GXP	Industry	Sector	S&P 500
Current Qtr.	35.70%	-3.40%	-37.00%	7.70%
Next Qtr.	30.50%	14.30%	-39.60%	15.40%
This Year	26.30%	1.50%	21.10%	0.40%
Next Year	5.80%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	24.99%	N/A	N/A	N/A
Next 5 Years (per annum)	7.10%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	18.28	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	2.57	3.52	3.48	1.36

Currency in USD.

IdaCorp, Inc. (IDA) - NYSE ★ Watchlist

71.73 0.17(0.24%) 11:41AM EDT - Nasdaq Real Time Price

Analyst Estimates

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	1.15	1.55	3.89	4.03
No. of Analysts	1.00	1.00	3.00	3.00
Low Estimate	1.15	1.55	3.85	3.95
High Estimate	1.15	1.55	3.92	4.09
Year Ago EPS	1.31	1.46	3.87	3.89

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	NaN	NaN	1.27B	1.29B
No. of Analysts			2	2
Low Estimate	NaN	NaN	1.26B	1.28B
High Estimate	NaN	NaN	1.29B	1.30B
Year Ago Sales	NaN	NaN	1.27B	1.27B
Sales Growth (year/est)	N/A	N/A	0.40%	1.30%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	1.07	1.54	0.64	0.53
EPS Actual	1.31	1.46	0.63	0.51
Difference	0.24	-0.08	-0.01	-0.02
Surprise %	22.40%	-5.20%	-1.60%	-3.80%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	1.15	1.55	3.89	4.03
7 Days Ago	1.15	1.55	3.89	4.03
30 Days Ago	1.15	1.55	3.89	4.02
60 Days Ago	1.15	1.55	3.89	4.02
90 Days Ago	N/A	N/A	3.89	4.00

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	IDA	Industry	Sector	S&P 500
Current Qtr.	-12.20%	-3.40%	-37.00%	7.70%
Next Qtr.	6.20%	14.30%	-39.60%	15.40%
This Year	0.50%	1.50%	21.10%	0.40%
Next Year	3.60%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	11.05%	N/A	N/A	N/A
Next 5 Years (per annum)	4.00%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	18.86	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	4.72	3.52	3.48	1.36

Currency in USD.

Otter Tail Corporation (OTTR) - NasdaqGS ★ Watchlist

Like 7

29.05 0.10(0.35%) 11:41AM EDT - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	N/A	N/A	1.55	1.60
No. of Analysts	N/A	N/A	1.00	1.00
Low Estimate	N/A	N/A	1.55	1.60
High Estimate	N/A	N/A	1.55	1.60
Year Ago EPS	0.36	0.42	1.56	1.55

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	194.00M	204.00M	798.90M	816.50M
No. of Analysts	1	1	1	1
Low Estimate	194.00M	204.00M	798.90M	816.50M
High Estimate	194.00M	204.00M	798.90M	816.50M
Year Ago Sales	188.15M	200.02M	779.80M	798.90M
Sales Growth (year/est)	3.10%	2.00%	2.40%	2.20%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.23	0.44	0.44	0.31
EPS Actual	0.36	0.42	0.41	0.38
Difference	0.13	-0.02	-0.03	0.07
Surprise %	56.50%	-4.50%	-6.80%	22.60%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	N/A	N/A	1.55	1.60
7 Days Ago	0.27	0.40	1.55	1.60
30 Days Ago	0.27	0.40	1.55	1.60
60 Days Ago	0.27	0.40	1.55	1.60
90 Days Ago	0.27	0.40	1.55	1.60

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	OTTR	Industry	Sector	S&P 500
Current Qtr.	N/A	-3.40%	-37.00%	7.70%
Next Qtr.	N/A	14.30%	-39.60%	15.40%
This Year	-0.60%	1.50%	21.10%	0.40%
Next Year	3.20%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	32.16%	N/A	N/A	N/A
Next 5 Years (per annum)	6.00%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	19.50	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	3.25	3.52	3.48	1.36

Currency in USD.

OTTR	Otter Tail Corp	-0.07%
IDA	Idacorp Inc	-0.18%
GXP	Great Plains Energy ...	-0.10%
ES	Eversource Energy	+0.20%
EDE	Empire District Elec...	+0.48%
EE	El Paso Electric Co	+0.02%
AEP	American Electric Po...	-0.31%
ALE	ALLETE Inc	+0.02%

PNM

PNM Resources, Inc. (PNM) - NYSE ★ Watchlist Like 7

32.22 0.16(0.50%) 11:42AM EDT - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.38	0.84	1.62	1.91
No. of Analysts	2.00	2.00	7.00	8.00
Low Estimate	0.35	0.78	1.58	1.85
High Estimate	0.40	0.90	1.65	1.95
Year Ago EPS	0.44	0.76	1.64	1.62

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	379.00M	448.00M	1.49B	1.59B
No. of Analysts	1	1	3	4
Low Estimate	379.00M	448.00M	1.48B	1.56B
High Estimate	379.00M	448.00M	1.50B	1.67B
Year Ago Sales	352.89M	417.43M	1.44B	1.49B
Sales Growth (year/est)	7.40%	7.30%	3.80%	6.60%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.41	0.74	0.18	0.14
EPS Actual	0.44	0.76	0.23	0.13
Difference	0.03	0.02	0.05	-0.01
Surprise %	7.30%	2.70%	27.80%	-7.10%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.38	0.84	1.62	1.91
7 Days Ago	0.38	0.84	1.62	1.91
30 Days Ago	0.40	0.83	1.63	1.91
60 Days Ago	0.40	0.83	1.63	1.91
90 Days Ago	0.43	0.73	1.63	1.92

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNM	Industry	Sector	S&P 500
Current Qtr.	-13.60%	-3.40%	-37.00%	7.70%
Next Qtr.	10.50%	14.30%	-39.60%	15.40%
This Year	-1.20%	1.50%	21.10%	0.40%
Next Year	17.90%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	19.54%	N/A	N/A	N/A
Next 5 Years (per annum)	8.76%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	20.28	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	2.32	3.52	3.48	1.36

Currency in USD.

Wed, May 18, 2016, 11:43AM EDT - U.S. Markets close in 4 hrs 17 mins Report an Issue

Pinnacle West Capital Corporation (PNW) - NYSE ★ Watchlist Like 6

72.52 0.36(0.49%) 11:43AM EDT - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	1.20	2.38	3.99	4.20
No. of Analysts	8.00	8.00	16.00	16.00
Low Estimate	1.10	2.29	3.90	4.15
High Estimate	1.33	2.47	4.05	4.24
Year Ago EPS	1.10	2.30	3.92	3.99

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	915.42M	1.21B	3.56B	3.66B
No. of Analysts	5	5	12	12
Low Estimate	904.04M	1.20B	3.49B	3.57B
High Estimate	934.35M	1.22B	3.62B	3.77B
Year Ago Sales	890.65M	1.20B	3.50B	3.56B
Sales Growth (year/est)	2.80%	1.10%	1.90%	2.70%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	1.23	2.32	0.26	0.12
EPS Actual	1.10	2.30	0.37	0.04
Difference	-0.13	-0.02	0.11	-0.08
Surprise %	-10.60%	-0.90%	42.30%	-66.70%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	1.20	2.38	3.99	4.20
7 Days Ago	1.20	2.37	4.00	4.20
30 Days Ago	1.23	2.34	4.00	4.20
60 Days Ago	1.22	2.35	4.00	4.20
90 Days Ago	1.23	2.32	3.99	4.18

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	1	1	0	1
Up Last 30 Days	3	4	2	4
Down Last 30 Days	0	0	2	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNW	Industry	Sector	S&P 500
Current Qtr.	9.10%	-3.40%	-37.00%	7.70%
Next Qtr.	3.50%	14.30%	-39.60%	15.40%
This Year	1.80%	1.50%	21.10%	0.40%
Next Year	5.30%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	-20.86%	N/A	N/A	N/A
Next 5 Years (per annum)	3.73%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	18.69	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	5.01	3.52	3.48	1.36

Currency in USD.

POR 0.10%

Portland General Electric Company (POR) - NYSE ★ Watchlist

Like 11

40.56 0.03(0.06%) 11:44AM EDT - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.44	0.44	2.13	2.36
No. of Analysts	5.00	4.00	11.00	13.00
Low Estimate	0.42	0.40	2.10	2.06
High Estimate	0.46	0.47	2.19	2.47
Year Ago EPS	0.44	0.40	2.04	2.13

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	451.58M	463.34M	1.98B	2.05B
No. of Analysts	3	3	9	10
Low Estimate	442.49M	413.70M	1.91B	1.96B
High Estimate	461.42M	499.76M	2.15B	2.22B
Year Ago Sales	450.00M	476.00M	1.90B	1.98B
Sales Growth (year/est)	0.40%	-2.70%	4.30%	3.40%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.41	0.48	0.62	0.61
EPS Actual	0.44	0.40	0.57	0.68
Difference	0.03	-0.08	-0.05	0.07
Surprise %	7.30%	-16.70%	-8.10%	11.50%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.44	0.44	2.13	2.36
7 Days Ago	0.44	0.44	2.13	2.36
30 Days Ago	0.45	0.49	2.25	2.38
60 Days Ago	0.43	0.48	2.25	2.41
90 Days Ago	0.45	0.48	2.28	2.41

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	0	1	1
Down Last 30 Days	1	1	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	POR	Industry	Sector	S&P 500
Current Qtr.	0.00%	-3.40%	-37.00%	7.70%
Next Qtr.	10.00%	14.30%	-39.60%	15.40%
This Year	4.40%	1.50%	21.10%	0.40%
Next Year	10.80%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	4.51%	N/A	N/A	N/A
Next 5 Years (per annum)	6.50%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	19.44	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	2.99	3.52	3.48	1.36

Currency in USD.

Westar Energy, Inc. (WR) - NYSE ★ Watchlist Like 18

52.14 0.57(1.11%) 11:45AM EDT - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.52	1.01	2.44	2.54
No. of Analysts	5.00	5.00	13.00	14.00
Low Estimate	0.47	0.87	2.40	2.46
High Estimate	0.55	1.10	2.50	2.66
Year Ago EPS	0.46	0.97	2.09	2.44

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	631.89M	770.06M	2.62B	2.69B
No. of Analysts	3	3	10	11
Low Estimate	614.30M	761.40M	2.53B	2.59B
High Estimate	645.21M	785.47M	2.81B	2.84B
Year Ago Sales	589.56M	732.83M	2.46B	2.62B
Sales Growth (year/est)	7.20%	5.10%	6.40%	2.80%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.42	1.03	0.36	0.46
EPS Actual	0.46	0.97	0.28	0.46
Difference	0.04	-0.06	-0.08	0.00
Surprise %	9.50%	-5.80%	-22.20%	0.00%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.52	1.01	2.44	2.54
7 Days Ago	0.52	1.01	2.44	2.54
30 Days Ago	0.52	1.03	2.44	2.53
60 Days Ago	0.50	1.03	2.44	2.53
90 Days Ago	0.48	1.00	2.44	2.58

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	1
Up Last 30 Days	0	0	2	3
Down Last 30 Days	1	1	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	WR	Industry	Sector	S&P 500
Current Qtr.	13.00%	-3.40%	-37.00%	7.70%
Next Qtr.	4.10%	14.30%	-39.60%	15.40%
This Year	16.70%	1.50%	21.10%	0.40%
Next Year	4.10%	227.80%	30.40%	12.90%
Past 5 Years (per annum)	20.59%	N/A	N/A	N/A
Next 5 Years (per annum)	4.93%	6.55%	6.23%	7.59%
Price/Earnings (avg. for comparison categories)	21.30	24.16	16.14	15.34
PEG Ratio (avg. for comparison categories)	4.32	3.52	3.48	1.36

Currency in USD.

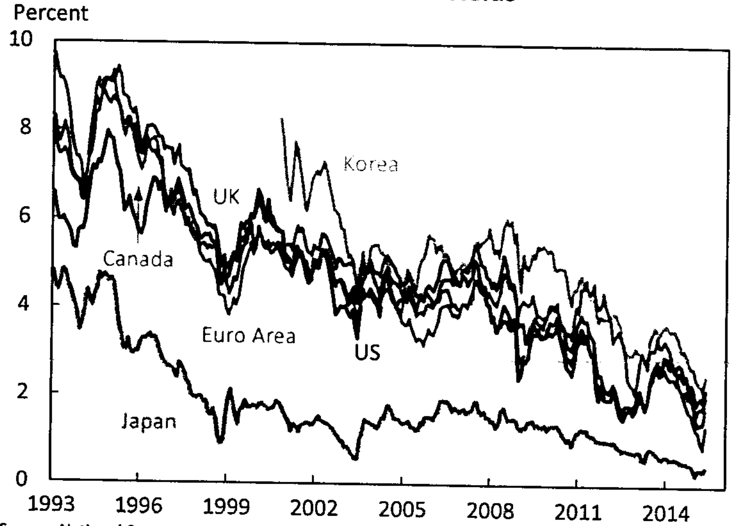
EXHIBIT 4

LONG-TERM INTEREST RATES: A SURVEY

July 2015

the fall in its rate over time less sharp, but other countries' rates have moved closer to Japan's levels in recent years. Real long-term interest rates have fallen as well. Nominal interest rates on 10-year bonds currently fall short of inflation in Japan, France, Canada, Sweden, and Denmark.[6] In Section IIIc, we discuss the role of global factors in determining interest rates.

Figure 4
Nominal 10-Year Yields



Source: National Sources

Forecasts Have Largely Missed the Decline in Long-Term Interest Rates

Past forecasts have largely missed the decline in long-term interest rates. This can be seen in Figure 5, which shows past private-sector forecasts along with the actual path of nominal 10-year Treasury rates since 1995.[7] Although economists' forecasts steadily declined after 1995, their pace of decline has lagged well behind the realized drop-off in interest rates. Indeed, since 1996, long-range private sector forecasts have exhibited a root mean square error of 2.7 percentage points relative to the nominal Treasury rate realized 10 years later.[8] The Administration's latest forecast for the nominal 10-year interest rate in 2025 is 4.4 percent, in line with the levels forecast by private-sector economists. The long-run forecast of 2.0 percent personal consumption expenditure (PCE) price-index inflation (the Federal Reserve's inflation target) implies an expected long-run long-term real interest rate of 2.4 percent for 2025.

Of course, it is difficult to make predictions about the very long run because so many conditions can change over that time horizon. However, even at shorter horizons, interest rate forecasts

---

[6] The real rate is once again measured as the annual rate on the 10-year government bond less the lagged and current 5-year moving average of annual CPI inflation.

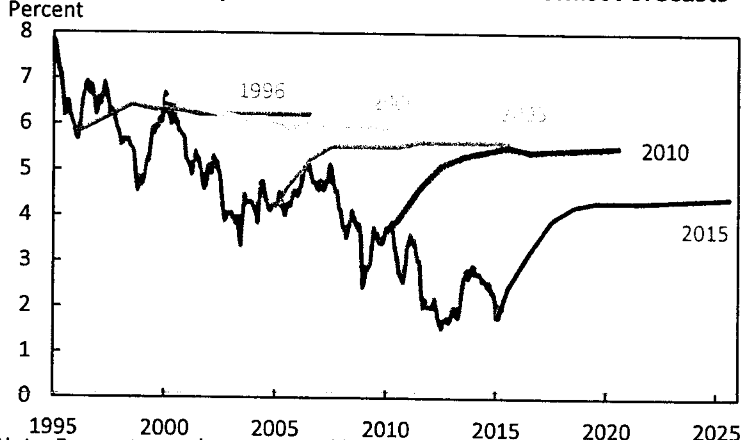
[7] The forecasts presented are those reported in the Blue Chip Economic Indicators survey in March of each calendar year, reflecting the average of over 50 professional forecasts. Similar patterns are evident in Administration forecasts reported in the annual *Economic Report of the President*.

[8] The root mean square error is a commonly used measure of the deviation between predicted and actual values. The difference between the two values is squared and then summed over time. The square root of that number is typically reported as a summary statistic, with large values indicating large prediction errors.

have tended to be inaccurate. Between 1984 and 2012, CBO, private-sector forecasters, and the Administration all systematically overestimated the path of nominal interest rates just two years into the future (CBO 2015a).

Figure 5

10-Year Treasury Rates and Historical Economist Forecasts



Note: Forecasts are those reported by Blue Chip Economic Indicators released in March of the given calendar year, the median of over 50 private-sector economists. Source: Blue Chip Economic Indicators, Aspen Publishers.

A central question in forming a long-run forecast is whether interest rates are statistically stationary—i.e., whether they have a tendency to return to a definite long-run mean value or average. To the extent interest rates are mean-reverting, the historical average may contain the most useful information for projecting the long-run long-term interest rate. On the other hand, if changes in interest rates are permanent (or at least, highly persistent), recent data may contain more useful information about long-run interest rates than historical data. In general, econometric tests suggest that real and nominal interest rates revert to their mean very slowly, with close to unit root (non-stationary)[9] properties.[10] Tests for non-stationarity tend to be weak, however, in that distinguishing between a true unit root and mean reversion with very high persistence is difficult in a finite sample of data (Neely and Rapach 2008).

Economic theory strongly suggests that real interest rates are bounded, if not fully mean reverting (as discussed in more detail in section III).[11] A high return on investment should trigger a reallocation of resources from consumption toward capital accumulation, driving down the marginal product of capital and the real interest rate over time. Similarly, a low return on

---

[9] A time series is said to contain a unit root if its random changes contain a permanent component. In this case it is statistically non-stationary.

[10] Hamilton et. al. (2015) reject the hypothesis that the real interest rate converges to a fixed constant. The difficulty in predicting the long-run real interest rate leads them to be skeptical of models, like the Ramsey model considered below, that place a strong emphasis on the link between output growth and the real interest rate.

[11] Even when interest rates are mean-reverting, and therefore stationary in the statistical sense, they can be "trend-stationary," reverting to means that evolve deterministically over time rather than being constants. Thus, stationarity of interest rates does not rule out the possibility that they trend upward or downward over long periods as a result of somewhat predictable, secular economic forces.

investment should induce consumers to increase current consumption and reduce capital investment, eventually driving up the real interest rate. Such economic forces should limit extremely high or extremely low real interest rates and work to push the rate back to intermediate levels. Indeed, were real interest rates to be literally non-stationary, the level of the real rate would pierce any upper or lower bound in finite time with a probability of one, an implication that is economically implausible and clearly not supported by the historical record.

In the current era of inflation targeting, inflation rates have tended to be moderate and stable, so the previous reasoning will by and large apply to the properties of nominal as well as real rates of interest. As noted above, however, interest rates do exhibit a high degree of persistence, raising the question of the underlying economic causes of long-run changes in interest rates and the forces that may be slowing their adjustment over time. We return to the specific question of why long-term interest rates are currently so low, and the implications for long-run equilibrium rates, in Section IV.

The data in Figure 5 suggest that past forecasts of long-term nominal interest rates have tended to err on the side of mean reversion. The long-run forecasts (the ends of the extended lines) lie within a fairly tight range of 4.4 to 6 percent, despite the fact that the nominal 10-year rate has swung from a low below 2 percent to a high of nearly 8 percent. The forecast range is consistent with the historical mean of the nominal long-term interest rate but may not accurately reflect possible changes in structural features of the economy. In light of the persisting downward trend in long-term interest rates, forecasters have incrementally lowered their expectations for the 10-year rate over the past two years, with the Administration forecast down by 60 basis points, the private-sector consensus forecast down by 30 basis points, and the CBO forecast down by 60 basis points.

Key Takeaways

- Real and nominal interest rates in the United States have been on a steady decline since the mid-1980s.
- Declining interest rates are a global phenomenon.
- It is difficult to forecast interest rates and forecasters largely missed the secular decline of the last three decades.

Tucson Electric Power Company
Test Year Ended June 30, 2015
Docket No. E-01933A-15-0322

SCHEDULES ATTACHED

SCHEDULE #

RBM - 1	WEIGHTED AVERAGE COST OF CAPITAL
RBM - 2	COST OF LONG TERM AND SHORT TERM DEBT
RBM - 3	COST OF COMMON EQUITY
RBM - 4	FAIR VALUE ADJUSTMENT
RBM - 5	DISCOUNTED CASH FLOW (DCF) MODEL
RBM - 6	CAPITAL ASSET PRICING (CAPM) MODEL
RBM - 7	COMPARABLE EARNINGS ANALYSIS
RBM - 8	ECONOMIC INDICATORS

Tucson Electric Power Company
Test Year Ended June 30, 2015
Docket No. E-01933A-15-0322

Schedule RBM-1

WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	Long - Term Debt	$ 1,441,656	$ -	$ 1,441,656	49.97%	4.32%	2.16%
2	Short - Term Debt	-	-	-	-	-	-
3	Common Equity	1,443,610	-	1,443,610	50.03%	9.20%	4.60%
4	TOTAL CAPITALIZATION	$ 2,885,266	$ -	$ 2,885,266	100.00%		6.76%
5	Fair Value Adjustment						0.54%
6	ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL						7.30%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) LINE 1 ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (E): LINE 3 - SCHEDULE RBM-3
COLUMN (F): COLUMN (D) x COLUMN (E)

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	Long - Term Debt	$ 1,441,656	$ -	$ 1,441,656	49.97%	2.76%	1.38%
2	Short - Term Debt	-	-	-	-	-	-
3	Common Equity	1,443,610	-	1,443,610	50.03%	7.64%	3.82%
4	TOTAL CAPITALIZATION	$ 2,885,266	$ -	$ 2,885,266	100.00%		
5	FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL						5.20%

Tucson Electric Power Company
Test Year Ended June 30, 2015
Docket No. E-01933A-15-0322

Schedule RBM-2
Page 1

COST OF LONG TERM and SHORT TERM DEBT (thousands of US dollars)

LINE NO.	DESCRIPTION	End of Test Year (Actual) (A) Actual as of 30-Jun-15	(B) Annual Interest	(C) Annual Cost Rate Taxable Bonds	End of Test Year (Proposed) (D) Actual as of 30-Jun-15	(E) Annual Interest	(F) Annual Cost Rate Taxable Bonds
	Fixed Rate Taxable Bonds:						
1	5.15% Series due 2021	$ 250,000	$ 12,875	-	$ 250,000	$ 12,875	-
2	3.85% Series due 2023	150,000	5,775	-	150,000	5,775	-
3	5.00% Series due 2044	150,000	7,500	-	150,000	7,500	-
4	3.05% Series due 2025	300,000	9,150	-	$ 300,000	$ 9,150	-
5	Total Fixed Rate Taxable Bonds	$ 850,000	$ 35,300	4.15%	$ 850,000	$ 35,300	4.15%
	Fixed Rate Taxable Bonds:						
6	4.500% 2012 Apache A	$ 177,000	$ 7,965	-	$ 177,000	$ 7,965	-
7	5.850% 2012 Pima A	16,465	741	-	16,465	741	-
8	4.000% 2013 Pima A	90,745	3,630	-	90,745	3,630	-
9	4.950% 2009 Pima A (San Juan)	80,410	3,980	-	80,410	3,980	-
10	5.125% 2009 Cocoino A	14,700	753	-	14,700	753	-
11	5.250% 2010 Pima A	100,000	5,250	-	100,000	5,250	-
12	Total Fixed Rate Tax-Exempt Bonds	$ 479,320	$ 22,319	4.66%	$ 479,320	$ 22,319	4.66%
	Variable Rate Tax-Exempt Bonds						
13	1982 Pima A Irvington	$ 38,700	$ 537	-	$ -	$ -	-
14	1982 Pima A Irvington & Four Corners	39,900	553	-	-	-	-
15	2013 Apache A	100,000	836	-	100,000	836	-
16	2010 Coconino A	36,700	355	-	36,700	$ 355	-
17	Total Variable Rate Tax-Expmpt Bonds	$ 215,300	$ 2,281	1.06%	$ 136,700	$ 1,191	0.87%
18	TOTAL LONG TERM DEBT	$ 1,544,620	$ 59,900	3.88%	$ 1,466,020	$ 58,810	4.01%
19 20	Unamortized Debt Discount, Premium and Expense and Loss on Reacquired Debt	(23,464)			(24,364)		
21 22	Amortization of Debt Discount and Expense and Loss on Reacquired Debt	-	2,791			3,190	
23	Credit Facility Commitment Fee	-	336			313	
24	Total Long Term Debt - Net of expenses	1,521,156	63,027		1,441,656	62,313	
25	Total Cost Long Term Debt			4.14%			4.32%
26	Adjustment for Inflation						1.56%
27	Total Cost Long Term Debt - Fair Value (Col (F)Ln 25 - (Col F) Ln 26)						2.76%

REFERENCES:
COMPANY SCHEDULE D-2; PAGE 1 OF 2

COST OF COMMON EQUITY

LINE NO.			
1	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	7.91% -- 9.65%	SCHEDULE RBM-5
2	CAPM METHODOLOGY	7.97%	SCHEDULE RBM-6
3	COMPARABLE EARNINGS ANALYSIS	8.50% - 9.30%	SCHEDULE RBM-7
4	RANGE OF REULTS	8.50% - 9.65%	
5	FINAL RUCO RECOMMENDED COST OF COMMON EQUITY	9.20%	TESTIMONY, RBM
6	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT	-1.56%	SCHEDULE RBM-4
7	COST OF COMMON EQUITY ESTIMATE - FAIR VALUE	7.64%	LINE 8 - LINE 9

Tucson Electric Power Company
Test Year Ended June 30, 2015
Docket No. E-01933A-15-0322

SCHEDULE RBM-4

FAIR VALUE ADJUSTMENT

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2009	1.66%	3.26%	1.61%
2	2010	1.15%	3.22%	2.06%
3	2011	0.55%	2.78%	2.23%
4	2012	0.42%	1.78%	1.36%
5	2013	0.80%	2.10%	1.30%
6	2014	0.49%	1.60%	1.11%
7	2015	0.10%	1.20%	1.10%
8	RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT - AVERAGE COLUMN (D)			1.56%

REFERENCES

COLUMNS (A) THRU (C), LINES 1 THRU 7: FEDERAL RESERVE BANK
COLUMN (D): COLUMN (C) - COLUMN (D)

DCF 90 DAY CONSTANT GROWTH

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) FIVE YEAR GROWTH YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.08	/	53.31	=	3.90%	3.97%	3.50%	3.00%	3.25%	6.96%	7.22%	7.47%
2	AEP	American Electric Power Company, Inc.	$ 2.24	/	61.84	=	3.62%	3.70%	5.00%	4.07%	4.54%	7.77%	8.24%	8.71%
3	EE	EL Paso Electric	$ 1.18	/	41.12	=	2.87%	2.96%	5.00%	7.00%	6.00%	7.94%	8.96%	9.97%
4	EDE	Empire District Electric Company	$ 1.04	/	31.11	=	3.34%	3.41%	2.50%	5.00%	3.75%	5.89%	7.16%	8.43%
5	ES	Eversource Energy	$ 1.78	/	54.56	=	3.26%	3.36%	6.00%	6.02%	6.01%	9.36%	9.37%	9.38%
6	GXP	Great Plains Energy Inc.	$ 1.05	/	29.07	=	3.61%	3.73%	5.50%	7.10%	6.30%	9.21%	10.03%	10.84%
7	IDA	IDACORP, Inc.	$ 2.04	/	70.62	=	2.89%	2.97%	7.50%	4.00%	5.75%	6.95%	8.72%	10.50%
8	OTTR	Otter Tail Corporation	$ 1.25	/	27.45	=	4.56%	4.65%	1.50%	6.00%	3.75%	6.10%	8.40%	10.70%
9	PNM	PNM Resources, Inc.	$ 0.88	/	31.98	=	2.75%	2.88%	10.00%	8.76%	9.38%	11.63%	12.26%	12.89%
10	PNW	Pinnacle West Capital Corporation	$ 2.50	/	68.37	=	3.66%	3.74%	5.00%	3.73%	4.37%	7.45%	8.10%	8.75%
11	POR	Portland General Electric Company	$ 1.20	/	38.29	=	3.13%	3.23%	6.00%	6.50%	6.25%	9.23%	9.48%	9.74%
12	WR	Westar Energy, Inc.	$ 1.52	/	44.61	=	3.41%	3.47%	3.00%	4.93%	3.97%	6.46%	7.44%	8.42%
13														
14		AVERAGE												
15							3.42%	3.51%	5.04%	5.51%	5.28%	7.91%	8.78%	9.65%
16														
17														

AVERAGE OF LOW, MEAN AND HIGH 8.78%

REFERENCES:
COLUMN (A); ANNUALIZED DIVIDENDS PER VALUE LINE (SEE EXHIBIT 1)
COLUMN (B): AVERAGE STOCK PRICES (SEE EXHIBIT 2)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): CALCULATED
COLUMN (E): VALUE LINE INVESTIMNT SURVEY (SEE EXHIBIT 1)
COLUMN (F): YAHOO FINANCE (SEE EXHIBIT 3)
COLUMN (G) COLUMN (E) + COLUMN (F)
COLUMNS (H), (I), (J): CALCULATIONS

CAPITAL ASSET PRICING MODEL

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	(A) r_f	+ [	ß	x (	r_m	-)]	=	(B) EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	2.64%	+ [	0.80	x	6.91%	]	=	8.17%
2	AEP	American Electric Power Company	k	=	2.64%	+ [	0.70	x	6.91%	]	=	7.48%
3	EE	EL Paso Electric	k	=	2.64%	+ [	0.75	x	6.91%	]	=	7.82%
4	EDE	Empire District Electric Company	k	=	2.64%	+ [	0.70	x	6.91%	]	=	7.48%
5	ES	Eversource Energy	k	=	2.64%	+ [	0.75	x	6.91%	]	=	7.82%
6	GXP	Great Plains Energy Inc.	k	=	2.64%	+ [	0.80	x	6.91%	]	=	8.17%
7	IDA	IDACORP, Inc.	k	=	2.64%	+ [	0.80	x	6.91%	]	=	8.17%
8	OTTR	Otter Tail Corporation	k	=	2.64%	+ [	0.85	x	6.91%	]	=	8.51%
9	PNW	Pinnacle West Capital Corporation	k	=	2.64%	+ [	0.80	x	6.91%	]	=	8.17%
10	PNM	PNM Resources, Inc.	k	=	2.64%	+ [	0.75	x	6.91%	]	=	7.82%
11	POR	Portland General Electric Company	k	=	2.64%	+ [	0.80	x	6.91%	]	=	8.17%
12	WR	Westar Energy, Inc.	k	=	2.64%	+ [	0.75	x	6.91%	]	=	7.82%
13												
14												
15	AVERAGE											7.97%

	20 Yr Treasury Bonds	30 Yr Treasury Bonds
February 2016	2.20%	2.62%
March 2016	2.28%	2.68%
April 2016	2.21%	2.62%
	2.23%	2.64%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

COMPARABLE EARNINGS ANALYSIS - PROXY COMPANIES
RATES OF RETURN ON COMMON EQUITY

Ln. No.		Company	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2019 - 2021	2002 - 2021
1	ALE	ALLETE, Inc.	12.4%	11.9%	11.9%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.5%	8.5%	8.5%	9.5%
2	AEP	American Electric Power Company, I	12.3%	12.4%	12.7%	11.9%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	10.0%	10.0%	10.0%	10.0%	10.7%
3	EE	EL Paso Electric				6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	8.0%	8.0%	8.5%	9.7%
4	EDE	Empire District Electric Company	8.4%	8.7%	5.7%	6.2%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	7.0%	7.0%	7.5%	9.0%	7.6%
5	ES	Eversource Energy				5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	9.0%	9.0%	9.5%	8.2%
6	GXP	Great Plains Energy Inc.	15.6%	16.6%	16.9%	13.7%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	5.8%	7.5%	7.5%	7.5%	9.0%
7	IDA	IDACORP, Inc.	7.1%	4.2%	8.2%	7.3%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.0%	9.0%	9.0%	8.5%
8	OTTR	Otter Tail Corporation	15.2%	12.0%	10.8%	11.6%	10.2%	10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.0%	9.5%	10.5%	8.8%
9	PNW	Pinnacle West Capital Corporation	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.5%	9.5%	10.0%	8.7%
10	PNM	PNM Resources, Inc.	6.3%	6.7%	7.9%	8.6%	7.2%	3.5%	0.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.9%	7.5%	8.0%	9.5%	6.4%
11	POR	Portland General Electric Company				5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.5%	9.0%	9.0%	7.9%
12	WR	Westar Energy, Inc.	5.0%	10.6%	7.7%	9.6%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	8.0%	9.0%	10.0%	10.5%	8.7%
13																				
14																				
15		Mean	10.1%	10.2%	10.0%	8.7%	9.0%	9.0%	7.2%	6.9%	7.8%	8.3%	8.2%	8.6%	8.7%	8.4%	8.5%	8.8%	9.3%	8.6%
16																				
17																				
18		Median	8.6%	10.6%	8.2%	8.0%	9.3%	9.7%	7.0%	6.8%	8.2%	8.7%	8.2%	8.9%	9.2%	8.3%	8.8%	9.0%	9.3%	8.7%
19																				

Source: Value Line Investment Survey.

ECONOMIC INDICATORS

Line No	Year	Real GDP Growth	Industrial Production Growth	Unemployment Rate	Consumer Price Index	Producer Price Index
1	1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
2	1976	5.4%	10.8%	7.7%	4.8%	3.7%
3	1977	5.5%	5.9%	7.0%	6.8%	6.9%
4	1978	5.0%	5.7%	6.0%	9.0%	9.2%
5	1979	2.8%	4.4%	5.8%	13.3%	12.8%
6	1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
7	1981	1.8%	1.9%	7.5%	8.9%	7.1%
8	1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
9	1983	4.0%	3.7%	9.5%	3.8%	0.6%
10	1984	6.8%	9.3%	7.5%	3.9%	1.7%
11	1985	3.7%	1.7%	7.2%	3.8%	1.8%
12	1986	3.1%	0.9%	7.0%	1.1%	-2.3%
13	1987	2.9%	4.9%	6.2%	4.4%	2.2%
14	1988	3.8%	4.5%	5.5%	4.4%	4.0%
15	1989	3.5%	1.8%	5.3%	4.6%	4.9%
16	1990	1.8%	-0.2%	5.6%	6.1%	5.7%
17	1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
18	1992	3.0%	3.1%	7.5%	2.9%	1.6%
19	1993	2.7%	3.4%	6.9%	2.7%	0.2%
20	1994	4.0%	5.5%	6.1%	2.7%	1.7%
21	1995	3.7%	4.8%	5.6%	2.5%	2.3%
22	1996	4.5%	4.3%	5.4%	3.3%	2.8%
23	1997	4.5%	7.3%	4.9%	1.7%	-1.2%
24	1998	4.2%	5.8%	4.5%	1.6%	0.0%
25	1999	3.7%	4.5%	4.2%	2.7%	2.9%
26	2000	4.1%	4.0%	4.0%	3.4%	3.6%
27	2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
28	2002	1.8%	0.2%	5.8%	2.4%	1.2%
29	2003	2.8%	1.2%	6.0%	1.9%	4.0%
30	2004	3.8%	2.3%	5.5%	3.3%	4.2%
31	2005	3.3%	3.2%	5.1%	3.4%	5.4%
32	2006	2.7%	2.2%	4.6%	2.5%	1.1%
33	2007	1.8%	2.5%	4.6%	4.1%	6.2%
34	2008	-0.3%	-3.4%	5.8%	0.1%	-0.9%
35	2009	-2.8%	-11.3%	9.3%	2.7%	4.3%
36	2010	2.5%	5.6%	9.6%	1.5%	4.7%
37	2011	1.6%	3.0%	8.9%	3.0%	4.7%
38	2012	2.2%	2.8%	8.1%	1.7%	1.4%
39	2013	1,5%	1.9%	7.4%	1.5%	0.8%
40	2014	2.4%	3.7%	6.2%	0.8%	-1.2%
41	2015	2.4%	1.3%	5.3%	0.7%	-3.7%

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Line No	Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
1	2003					
2	1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
3	2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
4	3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
5	4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
6	2004					
7	1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
8	2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
9	3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
10	4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
11	2005					
12	1st Qtr.	4.1%	3.8%	5.3%	4.4%	5.6%
13	2nd Qtr.	1.7%	3.0%	5.1%	1.6%	-0.4%
14	3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
15	4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
16	2006					
17	1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
18	2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
19	3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
20	4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
21	2007					
22	1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
23	2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
24	3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
25	4th Qtr.	2.9%	1.7%	4.8%	0.6%	6.5%
26	2008					
27	1st Qtr.	-1.8%	1.9%	4.9%	2.8%	9.6%
28	2nd Qtr.	1.3%	0.2%	5.3%	7.6%	14.0%
29	3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%	-0.4%
30	4th Qtr.	-8.9%	6.0%	6.9%	-13.2%	-28.4%
31	2009					
32	1st Qtr.	-5.3%	-11.6%	8.1%	2.4%	-0.4%
33	2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%	9.2%
34	3rd Qtr.	1.4%	-9.3%	9.6%	2.0%	-0.8%
35	4th Qtr.	4.0%	-4.5%	10.0%	2.5%	8.8%
36	2010					
37	1st Qtr.	1.6%	2.7%	9.7%	0.9%	6.5%
38	2nd Qtr.	3.9%	6.5%	9.7%	-1.2%	-2.4%
39	3rd Qtr.	2.8%	6.9%	9.6%	2.8%	4.0%
40	4th Qtr.	2.8%	6.2%	9.6%	2.8%	9.2%
41	2011					
42	1st Qtr.	-1.5%	5.4%	9.0%	4.8%	9.6%
43	2nd Qtr.	2.9%	3.6%	9.0%	3.2%	3.6%
44	3rd Qtr.	0.8%	3.3%	9.1%	2.4%	6.4%
45	4th Qtr.	4.6%	4.0%	8.7%	0.4%	-1.2%
46	2012					
47	1st Qtr.	2.3%	4.5%	8.3%	3.2%	2.0%
48	2nd Qtr.	1.6%	4.7%	8.2%	0.0%	-2.8%
49	3rd Qtr.	2.5%	3.4%	8.1%	4.0%	9.6%
50	4th Qtr.	0.1%	2.8%	7.8%	0.0%	-3.6%
51	2013					
52	1st Qtr.	1.9%	2.5%	7.7%	2.0%	1.2%
53	2nd Qtr.	1.1%	2.0%	7.6%	1.2%	2.4%
54	3rd Qtr.	3.0%	2.6%	7.3%	1.6%	0.0%
55	4th Qtr.	3.8%	3.3%	7.0%	1.2%	0.3%
56	2014					
57	1st Qtr.	-0.9%	3.2%	6.6%	1.6%	0.3%
58	2nd Qtr.	4.6%	4.2%	6.2%	3.6%	0.2%
59	3rd Qtr.	4.3%	4.7%	6.1%	0.0%	0.0%
60	4th Qtr.	2.1%	4.5%	5.7%	-2.8%	-0.8%
61	2015					
62	1st Qtr.	0.6%	3.5%	5.6%	-0.2%	-2.3%
63	2nd Qtr.	3.9%	1.5%	5.4%	0.6%	1.2%
64	3rd Qtr.	2.0%	1.1%	5.2%	0.0%	-1.8%
65	4th Qtr.	1.0%	-0.8%	5.0%	0.2%	-0.9%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Line No	Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
2	1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
3	1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
4	1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
5	1979	12.67%	10.04%	9.43%	9.86%	10.22%	10.49%	10.96%
6	1980	15.27%	11.51%	11.43%	12.30%	13.00%	13.34%	13.95%
7	1981	18.89%	14.03%	13.92%	14.64%	15.30%	15.95%	16.60%
8	1982	14.86%	10.69%	13.01%	14.22%	14.79%	15.86%	16.45%
9	1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
10	1984	12.04%	9.58%	12.46%	12.72%	13.66%	14.03%	14.53%
11	1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
12	1986	8.33%	5.98%	7.67%	8.92%	9.30%	9.58%	10.00%
13	1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
14	1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
15	1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
16	1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
17	1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
18	1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
19	1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
20	1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
21	1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
22	1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
23	1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
24	1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
25	1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
26	2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
27	2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
28	2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
29	2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
30	2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
31	2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
32	2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
33	2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
34	2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
35	2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
36	2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%
37	2011	3.25%	0.06%	2.78%		4.78%	5.04%	5.57%
38	2012	3.25%	0.09%	1.80%		3.83%	4.13%	4.86%
39	2013	3.25%	0.06%	2.35%		4.24%	4.47%	4.98%
40	2014	3.25%	0.03%	2.54%		4.19%	4.28%	4.80%
41	2015	3.27%	0.05%	2.14%		4.00%	4.12%	5.03%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

Tucson Electric Power Company
Test Year Ended June 30, 2015
Docket No. E-01933A-15-0322

INTEREST RATES

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	2007						
2	Jan	8.25%	4.96%	4.76%	5.78%	5.96%	6.16%
3	Feb	8.25%	5.02%	4.72%	5.73%	5.90%	6.10%
4	Mar	8.25%	4.97%	4.56%	5.66%	5.85%	6.10%
5	Apr	8.25%	4.88%	4.69%	5.83%	5.97%	6.24%
6	May	8.25%	4.77%	4.75%	5.86%	5.99%	6.23%
7	June	8.25%	4.63%	5.10%	6.18%	6.30%	6.54%
8	July	8.25%	4.84%	5.00%	6.11%	6.25%	6.49%
9	Aug	8.25%	4.34%	4.67%	6.11%	6.24%	6.51%
10	Sept	7.75%	4.01%	4.52%	6.10%	6.18%	6.45%
11	Oct	7.50%	3.97%	4.53%	6.04%	6.11%	6.36%
12	Nov	7.50%	3.49%	4.15%	5.87%	5.97%	6.27%
13	Dec	7.25%	3.08%	4.10%	6.03%	6.16%	6.51%
14	2008						
15	Jan	6.00%	2.86%	3.74%	5.87%	6.02%	6.35%
16	Feb	6.00%	2.21%	3.74%	6.04%	6.21%	6.60%
17	Mar	5.25%	1.38%	3.51%	5.99%	6.21%	6.68%
18	Apr	5.00%	1.32%	3.68%	5.99%	6.29%	6.82%
19	May	5.00%	1.71%	3.88%	6.07%	6.27%	6.79%
20	June	5.00%	1.90%	4.10%	6.19%	6.38%	6.93%
21	July	5.00%	1.72%	4.01%	6.13%	6.40%	6.97%
22	Aug	5.00%	1.79%	3.89%	6.09%	6.37%	6.98%
23	Sept	5.00%	1.46%	3.69%	6.13%	6.49%	7.15%
24	Oct	4.00%	0.84%	3.81%	6.95%	7.56%	8.58%
25	Nov	4.00%	0.30%	3.53%	6.83%	7.60%	8.98%
26	Dec	3.25%	0.04%	2.42%	5.93%	6.54%	8.13%
27	2009						
28	Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
29	Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
30	Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
31	Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%
32	May	3.25%	0.15%	3.29%	6.23%	6.49%	7.76%
33	June	3.25%	0.17%	3.72%	6.13%	6.20%	7.30%
34	July	3.25%	0.19%	3.56%	5.63%	5.97%	6.87%
35	Aug	3.25%	0.18%	3.59%	5.33%	5.71%	6.36%
36	Sept	3.25%	0.13%	3.40%	5.15%	5.53%	6.12%
37	Oct	3.25%	0.08%	3.39%	5.23%	5.55%	6.14%
38	Nov	3.25%	0.05%	3.40%	5.33%	5.64%	6.18%
39	Dec	3.25%	0.07%	3.59%	5.52%	5.79%	6.26%
40	2010						
41	Jan	3.25%	0.06%	3.73%	5.55%	5.77%	6.16%
42	Feb	3.25%	0.10%	3.69%	5.69%	5.87%	6.25%
43	Mar	3.25%	0.15%	3.73%	5.64%	5.84%	6.22%
44	Apr	3.25%	0.15%	3.85%	5.62%	5.81%	6.19%
45	May	3.25%	0.16%	3.42%	5.29%	5.50%	5.97%
46	June	3.25%	0.12%	3.20%	5.22%	5.46%	6.18%
47	July	3.25%	0.16%	3.01%	4.99%	5.26%	5.98%
48	Aug	3.25%	0.15%	2.70%	4.75%	5.01%	5.55%
49	Sept	3.25%	0.15%	2.65%	4.74%	5.01%	5.53%
50	Oct	3.25%	0.13%	2.54%	4.89%	5.10%	5.62%
51	Nov	3.25%	0.13%	2.76%	5.12%	5.37%	5.85%
52	Dec	3.25%	0.15%	3.29%	5.32%	5.56%	6.04%

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	2011						
2	Jan	3.25%	0.15%	3.39%	5.29%	5.57%	6.06%
3	Feb	3.25%	0.14%	3.58%	5.42%	5.68%	6.10%
4	Mar	3.25%	0.11%	3.41%	5.33%	5.56%	5.97%
5	Apr	3.25%	0.06%	3.46%	5.32%	5.55%	5.98%
6	May	3.25%	0.04%	3.17%	5.08%	5.32%	5.74%
7	June	3.25%	0.04%	3.00%	5.04%	5.26%	5.67%
8	July	3.25%	0.03%	3.00%	5.05%	5.27%	5.70%
9	Aug	3.25%	0.05%	2.30%	4.44%	4.69%	5.22%
10	Sept	3.25%	0.02%	1.98%	4.24%	4.48%	5.11%
11	Oct	3.25%	0.02%	2.15%	4.21%	4.52%	5.24%
12	Nov	3.25%	0.01%	2.01%	3.92%	4.25%	4.93%
13	Dec	3.25%	0.02%	1.98%	4.00%	4.33%	5.07%
14	2012						
15	Jan	3.25%	0.02%	1.97%	4.03%	4.34%	5.06%
16	Feb	3.25%	0.08%	1.97%	4.02%	4.36%	5.02%
17	Mar	3.25%	0.09%	2.17%	4.16%	4.48%	5.13%
18	Apr	3.25%	0.08%	2.05%	4.10%	4.40%	5.11%
19	May	3.25%	0.09%	1.80%	3.92%	4.20%	4.97%
20	June	3.25%	0.09%	1.62%	3.79%	4.08%	4.91%
21	July	3.25%	0.10%	1.53%	3.58%	3.93%	4.85%
22	Aug	3.25%	0.11%	1.68%	3.65%	4.00%	4.88%
23	Sept	3.25%	0.10%	1.72%	3.69%	4.02%	4.81%
24	Oct	3.25%	0.10%	1.75%	3.68%	3.91%	4.54%
25	Nov	3.25%	0.11%	1.65%	3.60%	3.84%	4.42%
26	Dec	3.25%	0.08%	1.72%	3.75%	4.00%	4.56%
27	2013						
28	Jan	3.25%	0.07%	1.91%	3.90%	4.15%	4.66%
29	Feb	3.25%	0.10%	1.98%	3.95%	4.18%	4.74%
30	Mar	3.25%	0.09%	1.96%	3.90%	4.15%	4.66%
31	Apr	3.25%	0.06%	1.76%	3.74%	4.00%	4.49%
32	May	3.25%	0.05%	1.93%	3.91%	4.17%	4.65%
33	June	3.25%	0.05%	2.30%	4.27%	4.53%	5.08%
34	July	3.25%	0.04%	2.58%	4.44%	4.68%	5.21%
35	Aug	3.25%	0.04%	2.74%	4.53%	4.73%	5.28%
36	Sept	3.25%	0.02%	2.81%	4.58%	4.80%	5.31%
37	Oct	3.25%	0.06%	2.62%	4.48%	4.70%	5.17%
38	Nov	3.25%	0.07%	2.72%	4.56%	4.77%	5.24%
39	Dec	3.25%	0.07%	2.90%	4.59%	4.81%	5.25%
40	2014						
41	Jan	3.25%	0.05%	2.86%	4.44%	4.63%	5.09%
42	Feb	3.25%	0.06%	2.71%	4.38%	4.53%	5.01%
43	Mar	3.25%	0.05%	2.72%	4.40%	4.51%	5.00%
44	Apr	3.25%	0.04%	2.71%	4.30%	4.41%	4.85%
45	May	3.25%	0.03%	2.56%	4.16%	4.26%	4.69%
46	June	3.25%	0.03%	2.60%	4.23%	4.29%	4.73%
47	July	3.25%	0.03%	2.54%	4.16%	4.23%	4.66%
48	Aug	3.25%	0.03%	2.42%	4.07%	4.13%	4.65%
49	Sept	3.25%	0.02%	2.53%	4.18%	4.24%	4.79%
50	Oct	3.25%	0.02%	2.30%	3.96%	4.06%	4.67%
51	Nov	3.25%	0.02%	2.33%	4.03%	4.09%	4.75%
52	Dec	3.25%	0.04%	2.21%	3.90%	3.95%	4.70%

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	2015						
2	Jan	3.25%	0.03%	1.88%	3.52%	3.58%	4.39%
3	Feb	3.25%	0.02%	1.98%	3.62%	3.67%	4.44%
4	Mar	3.25%	0.03%	2.04%	3.67%	3.74%	4.51%
5	Apr	3.25%	0.02%	1.94%	3.63%	3.75%	4.51%
6	May	3.25%	0.02%	2.20%	4.05%	4.17%	4.91%
7	June	3.25%	0.02%	2.36%	4.29%	4.39%	5.13%
8	July	3.25%	0.03%	2.32%	4.27%	4.40%	5.22%
9	Aug	3.25%	0.07%	2.17%	4.13%	4.25%	5.23%
10	Sept	3.25%	0.02%	2.17%	4.25%	4.39%	5.42%
11	Oct	3.25%	0.02%	2.07%	4.13%	4.29%	5.47%
12	Nov	3.25%	0.13%	2.26%	4.22%	4.40%	5.57%
13	Dec	3.50%	0.23%	2.24%	4.16%	4.35%	5.55%
14	2016						
15	Jan	3.50%	0.26%	2.09%			
16	Feb	3.50%	0.31%	1.78%			
17	Mar	3.50%	0.30%	1.89%			
18	Apr	3.50%	0.10%	1.81%			
19	May						
20	Jun						
21	Jul						
22	Aug						
23	Sep						
24	Oct						
25	Nov						
26	Dec						

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Line No	Year	S&P Composite	NASDAQ Composite	DJIA	S&P Dividend/Price Ratio	S&P Earnings/Price Ratio
1	1975			802.49	4.31%	9.15%
2	1976			974.92	3.77%	8.90%
3	1977			894.63	4.62%	10.79%
4	1978			820.23	5.28%	12.03%
5	1979			844.40	5.47%	13.46%
6	1980			891.41	5.26%	12.66%
7	1981			932.92	5.20%	11.96%
8	1982			884.36	5.81%	11.60%
9	1983			1,190.34	4.40%	8.03%
10	1984			1,178.48	4.64%	10.02%
11	1985			1,328.23	4.25%	8.12%
12	1986			1,792.76	3.49%	6.09%
13	1987			2,275.99	3.08%	5.48%
14	1988			2,060.82	3.64%	8.01%
15	1989	322.84		2,508.91	3.45%	7.41%
16	1990	334.59		2,678.94	3.61%	6.47%
17	1991	376.18	491.69	2,929.33	3.24%	4.79%
18	1992	415.74	$599.26	3,284.29	2.99%	4.22%
19	1993	451.21	715.16	3,522.06	2.78%	4.46%
20	1994	460.42	751.65	3,793.77	2.82%	5.83%
21	1995	541.72	925.19	4,493.76	2.56%	6.09%
22	1996	670.50	1,164.96	5,742.89	2.19%	5.24%
23	1997	873.43	1,469.49	7,441.15	1.77%	4.57%
24	1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
25	1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
26	2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
27	2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
28	2002	993.94	1,539.73	9,226.43	1.61%	2.92%
29	2003	965.23	1,647.17	8,993.59	1.77%	3.84%
30	2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
31	2005	1,207.06	2,099.03	10,547.67	1.83%	5.36%
32	2006	1,310.67	2,265.17	11,408.67	1.87%	5.78%
33	2007	1,476.66	2,577.12	13,169.98	1.86%	5.29%
34	2008	1,220.89	2,162.46	11,252.61	2.37%	3.54%
35	2009	946.73	1,841.03	8,876.15	2.40%	1.86%
36	2010	1,139.31	2,347.70	10,662.80	1.98%	6.04%
37	2011	1,268.89	2,680.42	11,966.36	2.05%	6.77%
38	2012	1,379.56	2,965.77	12,967.08	2.24%	6.20%
39	2013	1,642.51	3,537.69	14,999.67	2.14%	5.57%
40	2014	1,930.67	4,374.31	16,773.99	2.04%	5.25%
41	2015	2,061.20	4,943.49	17,590.61	2.10%	4.59%

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI

STOCK PRICE INDICATORS

Line No		S&P Composite	NASDAQ Composite	DJIA	S&P Dividends/Price Ratio	S&P Earnings/Price Ratio
1	**2004**					
2	1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
3	2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
4	3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
5	4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
6						
7	**2005**					
8	1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
9	2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
10	3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
11	4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
12						
13	**2006**					
14	1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
15	2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
16	3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
17	4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
18						
19	**2007**					
20	1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
21	2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
22	3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
23	4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
24						
25	**2008**					
26	1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
27	2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
28	3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
29	4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
30						
31	**2009**					
32	1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
33	2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
34	3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
35	4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
36						
37	**2010**					
38	1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
39	2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
40	3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
41	4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
42						
43	**2011**					
44	1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
45	2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
46	3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
47	4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
48						
49	**2012**					
50	1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
51	2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
52	3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
53	4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
54						
55	**2013**					
56	1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
57	2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
58	3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.65%
59	4th Qtr.	1,770.45	3,960.54	15,751.96	2.06%	5.42%
60						
61	**2014**					
62	1st Qtr.	1,834.30	4,210.05	16,170.26	2.04%	5.39%
63	2nd Qtr.	1,900.37	4,195.81	16,603.50	2.06%	5.26%
64	3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.38%
65	4th Qtr.	2012.04	4607.88	17368.36	2.03%	4.97%
66						
67	**2015**					
68	1st Qtr.	2063.46	4821.99	17806.47	2.02%	4.80%
69	2nd Qtr.	2102.03	5017.47	18007.48	2.05%	4.60%
70	3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
71	4th Qtr.	2,053.17	5,000.70	17,482.97	2.16%	4.23%

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI

EXHIBIT RUCO
3
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. W-01933A-15-0322

SURREBUTTAL TESTIMONY AND

SETTLEMENT TESTIMONY

OF

ROBERT MEASE

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 25, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Residential Utility Consumer Office's ("RUCO") has reviewed Tucson Electric Power Company's rebuttal testimony, and proposed Settlement Agreement in regards to its application for a permanent rate increase, filed with the Arizona Corporation Commission on November 5, 2015, and August 15, 2016, respectively, ("ACC" or "Commission") and RUCO recommends the following:

Capital Structure – RUCO recommended a capital structure consisting of 49.97% cost of long-term debt and 50.03% cost of common equity. The Company's and RUCO's recommended capital structure was adopted in the Settlement Agreement.

Cost of Debt – RUCO is recommending and the Company has agreed that the Commission adopt the Company's actual end of test year cost of long-term debt of 4.32 percent.

Cost of Equity Capital – RUCO recommended a cost of common equity of 9.20% in direct testimony compared to the Company's original request of 10.35%. RUCO accepted the 9.75% in final settlement as this has been the average authorized ROE's for State Jurisdictional Electric Utility Operations (Vertically Integrated) during years 2015 and 2016 as published by SNL Financial.

Original Cost Rate of Return – The Company has recommended and RUCO is in agreement that the ACC adopt a 7.04 percent weighted average cost of capital as the original cost rate of return ("OCROR") for TEP. RUCO's recommended rate of return represents the weighted cost of RUCO's recommended cost of common equity and cost of debt, subsequent to settlement discussions, and is 30 basis points lower than the 7.34 percent weighted average cost of capital originally proposed by the Company.

Fair Value Rate of Return – RUCO is in agreement that the Commission adopt a fair value rate of return ("FVROR") of 5.34 percent which includes a rate of return on the fair value increment of rate base of 1.00%.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is Robert B. Mease. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you previously provided testimony regarding this docket?

A. Yes. I filed testimony in this docket on June 3, 2016 specifically related to TEP's Capital Structure, Cost of Debt, Cost of Equity, Original Cost Rate of Return and Fair Value Rate of Return.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the settlement provisions as outlined in the Settlement Agreement as filed by the Company on August 15, 2016. RUCO believes that the terms as filed in the Settlement Agreement are just, reasonable, fair and in the public interest.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you will address in your surrebuttal testimony.

A. Based on the results of my analysis as well as final settlement discussions, I am making the following recommendations:

Capital Structure – RUCO recommended a capital structure consisting of 49.97% cost of long-term debt and 50.03% cost of common equity. The Company's and RUCO's recommended capital structure was adopted in the Settlement Agreement. The Company has no short-term debt.

Cost of Debt – RUCO is recommending that the Commission adopt the Company's actual end of test year cost of long-term debt of 4.32 percent.

Cost of Equity Capital – RUCO recommended a cost of common equity of 9.20% in direct testimony compared to the Company's original request of 10.35%. RUCO accepted the 9.75% in final settlement as this has been the average authorized ROE's for State Jurisdictional Electric Utility Operations (Vertically Integrated) during years 2015 and 2016 as published by SNL Financial.

Original Cost Rate of Return – RUCO is recommending that the ACC adopt a 7.04 percent weighted average cost of capital as the original cost rate of return ("OCROR") for TEP. RUCO's recommended rate of return represents the weighted cost of RUCO's recommended cost of common equity and cost of debt, subsequent to settlement discussions, and is 30 basis points lower than the 7.34 percent weighted average cost of capital originally proposed by the Company.

Fair Value Rate of Return – RUCO is recommending that the Commission adopt a fair value rate of return ("FVROR") of 5.34 percent which includes a rate of return on the fair value increment of rate base of 1.00%.

Q Why do you believe that RUCO's recommended 7.04 percent OCROR and 5.34 percent FVROR are appropriate rates of return for TEP to earn on its invested capital?

A. Both the OCROR and FVROR figures that have been agreed to by RUCO, TEP, and other intervening parties meet the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (320 U.S. 391, 1944).

Q. Does RUCO believe that their acceptance of the cost of equity and fair value adjustment in this case bounds RUCO to the same in rate cases going forward?

A. Absolutely not. If RUCO agrees with this position in this case it does not presuppose that RUCO will recommend or agree to this return on equity or fair value increment in future rate case applications.

Q. Does this conclude your testimony on TEP?

A. Yes, it does.

EXHIBIT
RUCO 4
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322 et al.

DIRECT TESTIMONY

OF

JEFFREY M. MICHLIK

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 3, 2016

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ATTACHMENTS

EXECUTIVE SUMMARY

Tucson Electric Power Company ("TEP or Company") is an Arizona "C" Corporation. TEP is a for-profit, certificated Arizona public service corporation that provides electric utility service to various communities in Pima County, Arizona. On November 5, 2015, TEP filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. The TEP corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

TEP Energy is a subsidiary of Fortis Inc., the largest investor-owned electric and gas distribution utility in Canada. UNS Energy is based in Tucson, Arizona and is the parent company of both Tucson Electric Power (TEP) and UniSource Energy Services (UES). TEP serves more than 414,000 customers in and around Tucson, while UES provides natural gas and electric service to about 243,000 customers in northern and southern Arizona. Electric service is provided through a UES subsidiary called UNS Electric, Inc., while natural gas service is provided through a subsidiary called UNS Gas, Inc.

The Company utilized a test year ended June 30, 2015.

<u>Rate Application denoted in thousands of dollars:</u>

The Company-proposed rates, as filed, produce total operating revenue of $1.051 billion, an increase of $109.534 million or 11.64 percent, over adjusted test year revenue of $941.031 million. The Company-proposed revenue will provide operating income of $165.900 million and a 5.69 percent rate of return on its proposed $2.913 billion fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $959.254 million an increase of $17.387 million or 1.85 percent, from the RUCO-adjusted test year revenue of $941.867 million. RUCO's recommended revenue will provide operating income of $134.398 million and a 5.20 percent return on the $2.582 billion RUCO-adjusted FVRB.

RUCO recommends that the Company provide the Commission with an annual report that documents the revenue normalization related to weather.

RUCO recommends that the Company in its next rate case filing not commingle its sales, and provide a break out of its unbilled sales, weather normalized sales, and customer annualized sales. Further, that the

Commission put the Company on notice that failure to provide this information may result in a disallowance of the entire adjustment.

RUCO recommends that in the future it is incumbent on the Company to provide all of the expense categories to support its membership expenses. Further, the Commission should send a strong message to the Company that ***all*** EEI membership may be disallowed in the future if this information is not provided.

Other Items:

RUCO recommends that the current PPFAC not be modified.

RUCO recommends that the current LFCR not be modified.

RUCO recommends that the current ECA not be modified.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Jeffrey M. Michlik. I am a Public Utilities Analyst V employed by the Arizona Residential Utility Consumer Office ("RUCO"). My business address is 1110 West Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. In my capacity as a Public Utilities Analyst V, I analyze and examine accounting, financial, statistical and other information and prepare reports based on my analyses that present RUCO's recommendations to the Arizona Corporation Commission ("Commission") on utility revenue requirements, rate design and other matters. I also provide expert testimony on these same issues.

Q. Please describe your educational background and professional experience.

A. In 2000, I graduated from Idaho State University, receiving a Bachelor of Business Administration Degree in Accounting and Finance, and I am a Certified Public Accountant with the Arizona State Board of Accountancy. I have attended the National Association of Regulatory Utility Commissioners' ("NARUC") Utility Rate School, which presents for study and review general regulatory and business issues. I have also attended various other NARUC sponsored events.

I joined RUCO as a Public Utilities Analyst V in September of 2013. Prior to my employment with RUCO, I worked for the Arizona Corporation Commission in the Utilities Division as a Public Utilities Analyst for a little over seven years. Prior to employment with the Commission, I worked one year in public accounting as a Senior Auditor, and four years for the Arizona Office of the Auditor General as a Staff Auditor.

Q. What is the scope of your testimony in this case?

A. I am presenting RUCO's analysis and recommendations on TEP's proposed revenue requirement for TEP's application for a permanent rate increase. I am also presenting testimony and schedules addressing rate base, operating revenues and expenses. In addition, Mr. Robert E. Mease will be addressing Cost of Capital, and Mr. Frank W. Radigan will be addressing plant, and rate design.

Q. What is the basis of your testimony in this case?

A. I performed a regulatory audit of the Company's application and records. The regulatory audit consisted of examining and testing financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission-adopted FERC Uniform System of Accounts ("USOA").

Q. How is your testimony organized?

A. My testimony is presented in six sections. Section I is this introduction. Section II provides a background of the Company. Section III is a summary of the Company's filing and RUCO's rate base and operating income adjustments. Section IV presents RUCO's rate base recommendations. Section V presents RUCO's operating income recommendations. Section VI presents RUCO's recommendations on other issues identified during RUCO's review of the application.

II. BACKGROUND

Q. Please review the background of this application.

A. Tucson Electric Power Company ("TEP or Company") is an Arizona "C" Corporation. TEP is a for profit, certificated Arizona public service corporation that provides electric utility service to various communities in Pima County, Arizona. On November 5, 2015, TEP filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. The TEP corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

Q. Can you provide additional background on UNS' corporate structure?

A. TEP Energy is a subsidiary of Fortis Inc., the largest investor-owned electric and gas distribution utility in Canada. UNS Energy is based in Tucson, Arizona and is the parent company of both Tucson Electric Power (TEP) and UniSource Energy Services (UES). TEP serves more than 415,000 customers in and around Tucson, while UES provides natural gas and electric service to about 243,000 customers in northern and southern Arizona. Electric service is provided through a UES subsidiary called UNS Electric, Inc., while natural gas service is provided through a subsidiary called UNS Gas, Inc.

III. SUMMARY OF FILING, RECOMMENDATIONS, AND ADJUSTMENTS.

Q. Please summarize the Company's proposals in this filing.

A. Based on the Company's schedules filed on May 5, 2015, the Company has proposed the following rounded to the nearest $1,000:

The Company-proposed rates, as filed, produce total operating revenue of $1.051 billion, an increase of $109.534 million or 11.64 percent, over adjusted test year revenue of $941.031 million. The Company-proposed revenue will provide operating income of $165.900 million and a 5.69 percent rate of return on its proposed $2.913 billion fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $959.254 million an increase of $17.387 million or 1.85 percent, from the RUCO-adjusted test year revenue of $941.867 million. RUCO's recommended revenue will provide operating income of $134.398 million and a 5.20 percent return on the $2.582 billion RUCO-adjusted FVRB (see RUCO schedule JMM-1).

Q. For the purposes of this rate case, has RUCO accepted the Company's gross revenue conversion factor of 1.6223?

A. Yes, see RUCO schedule JMM-2.

Q. Please summarize RUCO's rate base adjustments.

A. The four rate base adjustments are presented below:

Rate Base Adjustment No. 1 – Post-Test Year Plant and Renewables – This adjustment reverses the Company's pro-forma adjustment in the amount of $72,576,295 net of depreciation.

Rate Base Adjustment No. 2 – Market Value TEP Headquarters – This adjustment based on Commission Decision No. 60480, reduces the original cost of the building to market value, and results in an adjustment of $55,043,003 net of depreciation.

Rate Base Adjustment No. 3 – Jurisdictional Allocation – This adjustment revises plant based and accumulated depreciation based on a revision to the Company's Energy and Demand Allocation factors which results in an adjustment of $138,422,327 net of depreciation.

Rate Base Adjustment No. 4 - Allowance for Working Capital - This adjustment applies to the cash working capital and the prepaid insurance component of the Company's working capital allowance, and increases cash working capital by $2,011,254.

Q. Please summarize RUCO's operating revenue and expense adjustments.

A. The seventeen operating income adjustment(s) are presented below:

Operating Income Adjustment No. 1 – Weather Normalization – This adjustment removes $835,322 related to weather normalization that the Company has not substantiated.

Operating Income Adjustment No. 2 – Jurisdictional Allocation – This adjustment decreases expenses by $11,088,283 to account for a revision to the Company's Energy and Demand Allocation factors.

Operating Income Adjustment No. 3 – Reverse Credit Card Processing Fees – This adjustment reverses the credit card processing fees in the amount of $3,475,500 that the Company wants to spread to customers who do not pay their bills with credit cards.

Operating Income Adjustment No. 4 – Directors and Officers Liability Insurance – This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This reduces adjusted test year D&O expense by $25,153.

Operating Income Adjustment No. 5 – Lobbying, Employee Recognition, Spot Awards, and Wellness Expense - These adjustments reduces expenses that are not necessary to the provision of electric service and have been eliminated. These adjustments reduce adjusted test year expenses by $548,924.

Operating Income Adjustment No. 6 – Short-Term Incentive Program Expense - This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This adjustment reduces adjusted test year short-term incentive program expense by $3,666,994.

Operating Income Adjustment No. 7 – Supplemental Executive Retirement Plant ("SERP") Expense – This adjustment removes SERP expense that RUCO believes should not be borne by ratepayers, and is not necessary for the provision of electric services. This adjustment reduces SERP expense by $947,996.

Operating Income Adjustment No. 8 – Long-Term Incentive Expense ("LTI") – This adjustment removes items that RUCO believes should not be borne by ratepayers, and is not necessary for the provision of electric services. This adjustment reduces injuries and damages expense by $1,520,946.

Operating Income Adjustment No. 9 – Severance Pay – This adjustment removes items that RUCO believes should not be borne by ratepayers, and is not necessary for the provision of electric services. This adjustment reduces severance pay by $329,665.

<u>Operating Income Adjustment No. 10 – Edison Electric Institute ("EEI") Dues</u> – This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This adjustment reduces EEI dues by $204,267.

<u>Operating Income Adjustment No. 11 – Overhead and Outages</u> – This adjustment removes the Company's pro forma projection of expenses from 2016 to 2024 that are not known and measureable and instead uses a historical average from 2005 to 2015 to reflect overhaul and outages expenses on a going forward basis. This adjustment reduces expenses by $6,046,705.

<u>Operating Income Adjustment No. 12 – Rate Case Expense</u> – This adjustment reduces estimated rate case expense by $80,000 to account for what RUCO has determined to be just and reasonable.

<u>Operating Income Adjustment No. 13 – Depreciation Expense</u> – This adjustment reduces depreciation expense related to the rate base adjustments mentioned in the rate base section. In addition, adjustments were also made to Juan Unit 1 and Springerville generating stations, the result of both adjustments reduces depreciation expense by $18,456,271.

<u>Operating Income Adjustment No. 14 – Depreciation Expense and Other Expenses Associated with TEP Headquarters</u> – This adjustment reduces depreciation expense and increases/decreases other expenses related to TEP Headquarters. This results in a net decrease adjustment of $942,257.

Operating Income Adjustment No. 15 – Property Tax Expense – This adjustment reduces property tax expense related to post-test year plant in the amount of $564,897.

Operating Income Adjustment No. 16 – Interest Synchronization Expense – This adjustment resynchronizes interest expense based on RUCO's recommended rate base and weighted cost of debt and increases adjusted test year income taxes by $2,116,287.

Operating Income Adjustment No. 17 – Income Tax Expense – This adjustment increases income tax by $21,317,602 to account for RUCO's adjustments to operating revenues and expenses.

IV. RATE BASE

Fair Value Rate Base ("FVRB")

Q. Did the Company prepare a schedule showing the elements of a Reconstruction Cost New Depreciated ("RCND") Rate Base?

A. Yes. The Company derived its FVRB by taking the average of the Original Cost Rate Base ("OCRB") and RCND. This methodology has been accepted by the Commission in prior decisions.

Q. Has RUCO presented its schedules to reflect OCRB, RCND and FVRB?

A. Yes. For purposes of this presentation, I have used the Company's OCRB information as the starting point for RUCO's determination of the Company's FVRB.

Rate Base Summary

Q. Please summarize RUCO's adjustments to the Company's OCRB base denoted in thousands.

A. RUCO's adjustments to the Company's rate base resulted in a net decrease of $264 million, from $2.105 billion to $1.841 billion the decrease was primarily due to following RUCO's adjustments: (1) Removal of post-test year plant and post-test year plant – Renewables, (2) Market basing TEP headquarters, (3) Jurisdictional allocations and (4) allowance for working capital, as shown on schedules JMM-4, and 5.

Rate Base Adjustment No. 1 – Remove Post-Test Year Plant and Post-Test Year Plant - Renewables

Q. Has the Company proposed an adjustment to include post-test year plant and post-test year plant - renewables?

A. Yes. The Company proposes to include post-test year plant in the amount of $51,782,029 net of accumulated depreciation and post-test year plant – renewables of $20,794,266 net of accumulated depreciation.

Q. Does RUCO agree with the Company's inclusion of post-test year plant and post-test year plant – renewables?

A. No. For more details on RUCO's adjustment please see the direct testimony of RUCO witness Frank W. Radigan.

Q. What is RUCO's recommendation?

A. RUCO recommends removing all of the post-test year plant and post-test year plant – renewables, as shown in RUCO schedule JMM-6. In addition

RUCO has also removed the corresponding depreciation and property tax expense, which will be discussed in the operating income section.

Rate Base Adjustment No. 2 – Market Base TEP headquarters

Q. What adjustment is RUCO proposing?

A. RUCO is proposing to reduce the amount paid for the TEP headquarters to be consistent with a market base analysis that was ordered by the Commission in Decision No. 60480. For more details on RUCO's adjustment please see the direct testimony of RUCO witness Frank W. Radigan.

Q. What is RUCO's recommendation?

A. RUCO recommends decreasing the TEP headquarter costs to Market Base plant value, as shown in RUCO schedule JMM-7.

Rate Base Adjustment No. 3 – Jurisdictional Allocation

Q. What adjustment is RUCO proposing?

A. RUCO is proposing to change the energy and demand allocation factors utilized by the Company. For more details on RUCO's adjustment please see the direct testimony of RUCO witness Frank W. Radigan.

Q. What is RUCO's recommendation?

A. RUCO recommends decreasing net utility plant in service by $138,422,327, as shown in RUCO schedule JMM-8.

Rate Base Adjustment No. 4 – Allowance for Working Capital

Q. What is cash working capital?

A. Working capital measures the amount of investors' funds that must be used to sustain the day to day operations of the Company, in this case on average over a test year. In general the components of working capital are fuel inventory; materials and supplies inventories; prepayments; and cash working capital.

Q. Has RUCO made adjustments to any of these components?

A. Yes. RUCO has reduced the Company's Directors and Officers ("D&O") Insurance prepayments reflected in the allowance for working capital. Similarly, RUCO has reduced the Company's D&O expense, which will be discussed in greater detail in RUCO's Operating Adjustment No. 4. RUCO recommends a sharing of these costs between ratepayers and shareholder. In this case RUCO recommends a sharing of the D&O prepaid insurance of $41,658, RUCO recommends reducing prepaid D&O liability insurance by $20,829 from $41,658 to $20,829, as shown in RUCO schedule JMM-9.

RUCO has also adjusted the Company's cash working capital component based on its operating income adjustments to flow through the Company's lead-lag summary, and increases the cash working capital allowance by $2,032,083 from negative $10,734,427 to negative $8,670,770, as shown in RUCO schedule JMM-9.

V. OPERATING INCOME

Operating Income Summary

Q. What are the results of RUCO's analysis of test year revenues, expenses, and operating income?

A. RUCO's analysis resulted in adjusted test year operating revenues of $941.867 million, operating expenses of $818.186 million and operating income of $123.680 million, as shown on schedules JMM-10 and 11. RUCO made seventeen adjustments to operating income, as presented below.

Operating Income Adjustment No. 1 – Weather Normalization

Q. Did RUCO ask the Company to provide the amount of adjusted test year revenues related to its weather normalization adjustment?

A. Yes.

Q. What was the Company's response?

A. In response to RUCO data request 7.01 the Company stated the following: "The Company cannot break out the revenue adjustments by each component as requested. The weather normalization and customer annualization calculations are done separately for sales, but there is not a clean separation due to the cross-term, and the revenues are not calculated based on the separate components."

The Company did quantify that $3,854,000 of the $4,791,733 reduction to test year revenue was related to unbilled revenue. The remaining $937,733 that can be charged in each transaction by the customer is $750. Additional transactions would continue to be charged the full $3.50 convenience fee.[2]" Although Mr. Dukes in his testimony states on page 58 line 9, the amount is capped at $700.

Q. Did you examine the Company's pro forma adjustment for the proposed transaction?

A. Yes. The Company stated the following under its notes/assumptions:

(1) Card usage is estimated to increase approximately 70% over three years. 50% in year one and 10% in years 3 & 4.

(2) To limit credit card usage, customers will be charged $1.00 on the 1st credit card transaction during a billing cycle and pay entire cost on any additional credit card transactions.

Q. Did RUCO request interrogatories of the Company's proposal and pro formal adjustment?

A. Yes. In response to RUCO data request 5.01 the Company stated that years 1, 2 and 3 refer to years 2017, 2018 and 2019. The Company also stated the estimates were made by two independent industry leaders and not the Company. Currently the Company does not incur any of these costs as the $3.50 fee is paid by the customer directly to the third party vendor. Further, the Company stated that this would cause a cost shift.

[2] Ibid, line 21 page 5.

Q. What is RUCO's recommendation?

A. RUCO recommends denial of this unnecessary cost shift because first it is not based on cost of service – cost causation. Second the adjustment incorporates estimates of future years that are not known and measureable, and third the Company has not shown that they are harmed financially under the current methodology. RUCO has reversed the Company's proposal and eliminated the credit card processing fees in the amount of $3,475,500, as shown in RUCO schedule JMM-14.

Operating Income Adjustment No. 4 – Directors and Officers ("D&O") Liability Insurance Expense

Q. What is D&O Liability Insurance?

A. D&O liability Insurance is liability insurance that covers directors and officers for claims made against them by shareholders or others for decisions they may make.

Q. Has the Company requested that ratepayers bear the full burden of this cost?

A. Yes.

Q. What is the total amount of D&O Liability Insurance included in adjusted test year expenses?

A. $50,306.

Q. What is RUCO's recommendation?

A. RUCO recommends a 50/50 sharing between ratepayers and shareholders, since D&O Liability Insurance not only benefits ratepayers, but also shareholders. Shareholders benefit from insurance coverage in litigation cases brought against the Company's Directors and Officers. Shareholders would also benefit from payments under this policy which may not be recoverable from ratepayers. Similarly, it can be argued that ratepayers benefit, since the Company can attract and retain directors and officers, and provides them with some degree of freedom from personal liability. Therefore, it is reasonable for shareholders to bear a portion of the cost for the D&O liability insurance. RUCO recommends reducing D&O liability insurance by $25,180 from $50,306 to $25,180, as shown in RUCO schedule JMM-15.

Operating Income Adjustment No. 5 – Lobbying costs, Employee Recognition, Spot Awards, and Wellness Expenses

Q. Has the Company asked ratepayers to pay for lobbying costs, employee recognition, spot awards, and wellness expenses?

A. Yes.

Q. Did RUCO subsequently ask for the ACC jurisdictional ratio for these expense categories in data request 11.15?

A. Yes. The Company provided the ACC jurisdictional amounts along with any other adjustments made to these amounts.

Q. Is the Company asking ratepayers to pay for any wellness programs?

A. Yes. In RUCO data request 11.14 the Company is seeking recovery of wellness program administrative expense of $53,133, and wellness program expense of $117,642.

Q. Does RUCO believe these costs are necessary for the provision of electrical services?

A. No, and these costs should be absorbed by the shareholders.

Q. What is RUCO's recommendation?

A. RUCO recommends reducing administrative and general expense by $548,924, as shown in RUCO schedule JMM-16.

Operating Income Adjustment No. 6 – TEP Short-Term Incentive Program ("PEP")

Q. Has the Company asked for ratepayers to fund 100 percent of its incentive compensation program?

A. Yes.

Q. Briefly describe the PEP?

A. According to Company data request Uniform Data Request ("UDR") 1.034, Incentives:

"All TEP non-union employees participate in UNS's short-term incentive program ("PEP"), which is tied to annual compensation. The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2015, the objectives were (i) net income; (ii) managing long-term O&M; and (iii) excellent operations and safe work environment, which include both quantitative and qualitative measures. The Compensation Committee selected the goals and individual weightings for the 2015 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, and process improvements. This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS's various stakeholders. The outcomes of which all benefit our customers in the long run.

The financial and other metrics for the Company's 2015 Short-Term Incentive Compensation program were:

- Financial – 60%
  - Net Income – 40%
  - Managing Long-term O&M – 20%
- Excellent Operations and Safe Work Environment – 40%"

Q. What are the amounts of the PEP test year expense and Pro-forma amount?

A. The Company is requesting $6,929,542 in test year expenses and $2,243,378 in post-test year expenses for a total of $9,172,920, as shown in RUCO schedule JMM-17.

Q. Does RUCO agree with the calculation of the Pro-forma amount?

A. No. The Company has utilized a historic two year average, but then has imbedded a 2 percent increase each year. For example, the Company used historic 2013 incentive expense data and then inflated this number by 2 percent for four years out to 2017. As a result this inflates your two year historic data by $521,185 (i.e. $9,172,920 - $8,651,735)

Q. Has RUCO recalculated this amount?

A. Yes. RUCO's has removed the 2 percent per year inflator that was imbedded in the historic data. RUCO then recommends as explained below a sharing of the adjusted expense between shareholder and ratepayer.

Q. Does PEP benefit both ratepayers and shareholders?

A. Yes. As the Company stated above.

Q. What is RUCO's recommendation?

A. RUCO recommends that incentive compensation expense be reduced by $3,666,994 after application of the ACC jurisdictional ratio, as shown in RUCO schedule JMM-17.

Operating Income Adjustment No. 7 – Supplemental Executive Retirement Plan ("SERP") expense

Q. What is a SERP?

A. A SERP is defined as "a deferred compensation agreement between the company and the key executive whereby the company agrees to provide supplemental retirement income to the executive and his family if certain pre-agreed eligibility and vesting conditions are met by the executive."[3]

Q. What is the amount of SERP expense that the Company is seeking to recovery from ratepayers in this case?

A. The Company is seeking to recovery $947,996 from ratepayers in this case.

Q. Does RUCO agree that ratepayers should pay for these costs?

A. No. RUCO does not consider the cost of supplemental benefits for high-ranking officers necessary to the provision of electric service. Company officials are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. RUCO believes that any excess or additional perks given to a select group of employees should be borne by the Company's shareholders, and not ratepayers.

Q. Has the Commission disallowed SERP in prior rate decisions?

A. Yes. See Southwest Gas (Decision No. 68487, dated February 23, 2006), Arizona Public Service, (Decision No. 69663, dated June 28, 2007), and UNS Gas (Decision No. 70011, dated November 27, 2007).

Q. Did the Company request the recovery of SERP costs in its last rate case?

A. No.

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3 Definitions from BoliColi.com

Q. What is RUCO's recommendation?

A. RUCO recommends that $947,996 in SERP expenses be removed, as shown on schedule JMM-18.

Operating Income Adjustment No. 8 – Long-Term Incentive ("LTI") Compensation

Q. What is the amount of LTI expense that the Company is requesting be recovered by ratepayers in this case?

A. The Company is requesting that $1,683,829 in LTI be recovered from ratepayers in this case.

Q. Did the Company ask for recovery of LTI expense in the last rate case or the rate case before?

A. No.

Q. What was the Company's reason for not requesting LTI expense in the previous two cases?

A. The Company stated in RUCO data request 5.2 that "because of the size of the revenue request in the last rate case, the Company decided to not request long-term incentive compensation in this last rate case, but reserved the right to request it in this case."

Q. How is the Company's LTI Plan administered?

A. Based on RUCO's interpretation which is based on the Company's statement below, long-term incentive compensation ties executive compensation to the Company's financial results in the future.

"The Long-Term Incentive Compensation ("LTI") program is comprised of Performance Units ("PU") and Restricted Stock Units ("RSU"). The program is designed to: (1) ***place a focus on long-term performance, linking a portion of the compensation of executive officers to the achievement of multi-year financial results***, and (2) serve as a retention tool for executive talent. These objectives are achieved by a three-year vesting schedule inherent in each annual LTI award. The PUs will result in cash compensation to the extent that the three-year cumulative financial target is achieved. RSUs also pay out in cash and vest over three years to serve as a retention tool."

Q. Did the Company point to any benefits for ratepayers?

A. Yes. The Company states it will keep management and reduce long-term operating costs in the future.

Q. What concerns does RUCO have with the LTI expense?

A. First, the LTI expense is already limited to adequately compensated executives.

Second, unlike the short-term incentive PEP program mentioned above, the compensation is tied to financial performance, and nothing else which benefits the Company and its shareholders. There is nothing tied to reliability and quality of service for its ratepayers.

Third, if the program is successful and generates earnings for the Company the Company should use its earnings to fund the on-going program, and not ask that the burden to be placed 100 percent on ratepayers.

Fourth, the LTI compensation of the Company executive is tied to a three year period of time related to the financial statements and to the Company's stock price, this creates an incentive for the employee to make business decisions from the perspective of shareholders, and therefore, there is an alignment of interest between the Company executive and its shareholder.

RUCO believes it is not appropriate to ask ratepayers to bear the costs of incentive plans designed to encourage utility executives to put the financial interest of its shareholders ahead of its ratepayers. Especially since the financial statements are strengthened by increases in utility rates and underlying adjustor mechanisms that may be adopted. Higher rates are beneficial for shareholders while higher rates are detrimental to ratepayers.

While cost containment is important to ratepayers, RUCO expects the Company, as part of the regulatory compact to act in the best interest of its customers and control costs with or without an incentive compensation program.

Q. Does it matter if the LTI plan is reasonably benchmarked with other peers?

A. No it does not matter that the Company's financial-based incentives are set at a reasonable level, if it is determined by the Commission that these costs are not reasonable for ratemaking purposes, as this commission has done in the past.

Q. What is RUCO's recommendation?

A. RUCO recommends the removal of all LTI expense, as shown in Schedule JMM-19.

Operating Income Adjustment No. 9 – Severance Pay

Q. Has the Company asked for severance pay in this case?

A. Yes, the Company has asked ratepayers to pay for $365,688 in severance pay expense in this case.

Q. What is severance payout?

A. An employee is given a severance pay package after the employee separates from the Company which may be the result of an early retirement, layoff, resign or a termination.

Q. Was the Company able to explain who was separated and why the severance pay was paid?

A. No, the Company stated in response to Staff data request 7.14 that "Individual severance agreements contain confidentiality agreements that would preclude us from providing names of such employees and the details of the circumstances resulting in the severance payment without their consent. Although we cannot identify each employee individually, the severance payments are generally made to employees at the middle management or professional level or higher, and is consistent with requests made in prior rate cases."

Q. Does RUCO believe ratepayers should pay extra compensation to middle management or higher level management when they separate from the Company?

A. No, this is a cost that should be borne solely by the shareholders.

Q. What is RUCO's recommendation?

A. RUCO recommends the removal of $329,665 in severance pay, as shown in Schedule JMM-20.

Operating Income Adjustment No. 10 – Edison Electric Institute ("EEI") Dues

Q. Did the Company remove any EEI Utility Air Regulation Group ("UARG") membership dues, or Contributions to the Edison Foundation and Avian Power line?

A. No.

Q. Whose interest do these groups represent?

A. These groups represent the interest of electric generators such as UNS and TEP, donations and membership is purely voluntary, many of which are political in nature, and may not be necessary for the provision of utility services.

Q. Has the Company already reduced EEI Membership – USWAG, and EEI Industry Issues for legislative advocacy?

A. Yes. The Company removed $79,368.

Q. What has the Commission recommended in prior Decisions?

A. The Commission recommended a reduction in EEI dues of 49.93 percent in Decision No. 71914 and 70860.

Q. How was this percentage determined?

A. The percentage was determined using the following NARUC Operating Expense Categories:[4]

NARUC Operating Expense Categories	Percentage of Dues
Legislative Advocacy	20.38%
Regulatory Advocacy	16.49%
Advertising	1.67%
Marketing	3.68%
Public Relations	7.71%
Total Expenses	49.93%

Q. Has RUCO updated this information from EEI?

A. Unfortunately RUCO cannot. After 2006, the EEI stopped providing this information. RUCO believes after a series of regulatory partial disallowances of EEI dues by Commissions across the nation, EEI decided

[4] Based on the Edison Electric Institute Schedule of Expenses by NARUC Category For Core Dues Activities for the Year Ended December 31, 2005.

not to provide this information to NARUC, which it had previously done for at least a decade.

Q. So in other words, the letter the Company received from EEI only addresses one expense category- Legislative Advocacy?

A. Yes. The letter provides no information on the other eight expense categories. It only makes sense that most of these costs have been shifted elsewhere, but RUCO does not know where because EEI does not supply an expense report anymore that has these details.

Q. What is RUCO's recommendation?

A. RUCO recommends a disallowance of 50 percent of these categories.

RUCO recommends that in the future it is incumbent on the Company to provide all of the expense categories to support its EEI dues categories. Further, the Commission should send a strong message to the Company that all EEI dues may be disallowed in the future if this information is not provided.

In summary, RUCO recommends an additional disallowance of EEI dues in the amount of $204,267, as shown in RUCO schedule JMM-21.

Operating Income Adjustment No. 11 – Overhaul and Outage Expense

Q. Is RUCO recommending a reduction to the Company's pro forma adjustment to Overhaul and Outage Expense?

A. Yes. RUCO is proposing a reduction to test year expense by $6,046,705.

Q. How did the Company calculate their test year adjustment to this expense?

A. The company computed an estimated average annual cost based on projected amounts for years 2016 through and including 2024, for each plant. The projected cost for each type of overhaul, major and minor was then applied to the frequency for each plant where a major or minor overhaul was projected to occur. The projected average was then compared to the test year amount, and a pro forma adjustment was made.

Q. Why does RUCO disagree with methodology used by the Company?

A. First, projecting costs from 2016 through 2024, does not comply with sound rate making principles of costs being known and measurable. Second, Arizona uses a historic test year and not a future test year for determining rates. Third, using estimate costs always results in errors. Finally, the Company will likely file a new rate case before 2024 with more accurate cost data.

Q. Does RUCO have any other concerns?

A. Yes. Future EPA regulations could cause the rapid closure of the Company's remaining coal fleet, in which case the Company would pocket any customer prepayments. Therefore, it seems unwise to shift the risk to customers and have them prepay these estimated future costs.

Q. Is there anything else that RUCO examined?

A. Yes, RUCO looked at the pro forma adjustment the Company proposed in its last rate case.

Q. What were the results?

A. As can be expected with projections into the future, the amounts and timings of the overhauls were different than what the Company had projected in its last case.

Q. Please describe RUCO's methodology and recommendation?

A. From the Company's pro forma excel worksheet RUCO utilized historical data from 2005 to 2015 to develop an average cost which includes both major and minor repairs. RUCO then compared this average to the test year amount, and made a pro forma adjustment, as shown on Schedule JMM-22.

Operating Income Adjustment No. 12 – Rate Case Expense

Q. What has the Company requested as an estimate of rate case expense to be authorized in this case?

A. The Company has its estimated $1,210,000 in rate case expense to be amortized over 3 years.

Q. What was the amount of Rate Case Expense requested and authorized by the Commission in prior cases?

A. In Decision No. 70628 (dated December 1, 2008), the Company requested $900,000 in estimated rate case expense and was authorized $900,000. In Decision No. 73912 (dated June 27, 2013), the Company requested $1,415,000 in estimated rate case expense and was authorized $900,000 according to the Company in its response to RUCO 5.4.

Q. When asked, did the Company explain the difference between this case and the prior case that would necessitate an increase in rate case expense?

A. Yes. The Company in response to RUCO data request 11.03, stated that "In the previous rate case, the Company included a $140,000 Tax Adjustment Study and a $180,000 Generation Decommissioning Study in its estimate of rate case expenses. Since these studies were not performed for the current rate case, no estimated was included in the current request for rate case expenses."

Q. What does RUCO recommend as a reasonable allowance for rate case expense in this proceeding?

A. RUCO recommends $950,000 in rate case expense to be normalized over three years, as shown is RUCO Schedule JMM-23.

Operating Income Adjustment No. 13 – Depreciation Expense

Q. Please explain the removal of Depreciation Expense from Post-Test Year Plant and Post-Test Year Plant – Renewables?

A. As explained earlier in Rate Base Adjustment No. 1, this adjustment is a companion entry that removes the depreciation expense related to Post-Test Year Plant and Post-Test Year Plant – Renewables. As a result, RUCO has removed $8,931,022 from operating expenses as shown in RUCO Schedule JMM-24.

In addition, RUCO has adjusted the depreciation expense related to San Juan Unit 1 and Springerville in the amount of $9,325, 249, as also shown in this schedule. For more information on this adjustment see the direct testimony of Frank W. Radigan.

Operating Income Adjustment No. 14 – Depreciation Expense and Other Expenses Associated with TEP Headquarters

Q. Please explain the adjustment to depreciation expense and other expenses associated with TEP headquarters?

A. As explained earlier in Rate Base Adjustment No. 2, this adjustment is a companion entry that adjusts depreciation expense and other expenses associated with the market basing of TEP Headquarters. As a result, RUCO has removed $942,257 from operating expenses as shown in RUCO Schedule JMM-25.

Operating Income Adjustment No. 15 – Remove Property Tax Expense for Post-Test Year Plant and Post-Test Year Plant – Renewables.

Q. Please explain the removal of Property Tax Expense for Post-Test Year Plant and Post-Test Year Plant - Renewables?

A. As explained earlier in Rate Base Adjustment No. 1, this adjustment is a companion entry that removes the property tax expense related to Post-Test Year Plant and Post-Test Year Plant – Renewables. As a result, RUCO has removed $564,897 from operating expenses, as shown in RUCO Schedule JMM-26.

Operating Income Adjustment No. 16 – Interest Synchronization

Q. Please explain interest synchronization?

A. An interest synchronization adjustment is done to insure that the revenue requirement reflects the tax savings generated by the interest component of the revenue requirement. The interest synchronization expense is calculated by multiplying the rate base by the weighted average cost of debt. The combined state and federal income tax rates are then applied to the resulting interest deduction difference to determine the income tax expense adjustment.

Q. Has RUCO made an adjustment for interest synchronization?

A. Yes. Since the Company's rate base differs from RUCO's recommended rate base, an adjustment was required. RUCO's adjustment increases interest synchronization by $2,116,287, as shown is RUCO Schedule JMM-27.

Operating Income Adjustment No. 17 – Income Tax Expense

Q. Has RUCO adjusted income taxes as a result of its adjustments, mentioned above?

A. Yes. RUCO applied the statutory state and federal income tax rates to RUCO's taxable income. As a result, RUCO has increased income tax expenses for the adjusted test year by $21,317,602, as shown in RUCO schedule JMM-28.

VI. OTHER ISSUES

Adjustors

Q. Has the Company asked to make modifications to its Commission approved existing adjustors?

A. Yes, the Company has asked adjustments be made to the Purchased Power Fuel Adjustment Clause ("PPFAC"), Environmental Compliance Adjustor ("ECA"), and Lost Cost Fixed Recovery ("LFCR") adjustors.

<u>Changes to the PPFAC</u>

Q. Has the Company asked to have its PPFAC modified?

A. Yes. The Company proposes the following:

- The changes include modifying the PPFAC rate to adjust monthly based on a historic 12-month rolling average (as compared to changing the PPFAC rate once a year).
- In addition, the Company is proposing that the PPFAC rate be calculated as a percentage of a customer's base fuel rate, rather than as a single per kilowatt hour (kWh) energy rate that is applied to all customers.

Q. Does RUCO agree with the Company's proposed adjustments?

A. No. RUCO has concerns the current percent band reduces the impact of the PPFAC to ratepayers. The base rate annual adjustment also exposes the ratepayers to more risk, which has not been compensated by a reduction in the Company's return on equity. RUCO recommends that the current PPFAC not be modified.

Changes to the LFCR

Q. Has the Company asked to have its LFCR mechanism modified?

A. Yes.

- The Company has proposed that it be allowed to recover 100 percent of lost fixed costs attributable to generation (currently zero) and to be allowed to recover 100 percent of demand revenues (currently 50 percent).
- The Company wishes to increase the cap from 1 percent to 2 percent of test year revenues.
- The Company is also proposing to simplify the percentage-based LFCR Adjustment to be a single rate applied to customers' bills, rather than split the adjustment into two separate rates for Energy Efficiency ("EE") and Distributed Generation ("DG").

Q. Putting aside the legal issues surrounding the LFCR, what is RUCO's recommendation?

A. Any increase in the percentage cap or recovery of 100 percent generation and 100 percent of demand revenues exposes ratepayers to more risk, which has not been compensated by a reduction in the Company's return on equity. Further, the commingling of DG and EE line items in the customer's bill will only serve to confuse the customer, and for accounting purposes does not provide transparency. RUCO recommends that the current LFCR not be modified.

Q. What has been RUCO's position in the past regarding the LFCR, in this case and in other cases?

A. RUCO has agreed in the past not to oppose the LFCR as long as the LFCR provided an opt-out provision for ratepayers. RUCO has never said the LFCR qualifies as a legal adjustor mechanism. RUCO did not oppose the LFCR as part of the previous settlements because the opt-out provision provided ratepayers with an undisputed legal option to address the Company's fixed-cost concerns.

Q. With the advent of the recent Court of Appeals decision regarding the System Improvement Benefit ("SIB") Mechanism, has RUCO changed its position on the LFCR?

A. No. RUCO is reviewing the legality of the LFCR in light of the Court's opinion.

<u>**Changes to the ECA**</u>

Q. What is the ECA and how does it work?

A. As stated on the Company's website "The ECA is a charge that allows TEP to recover a portion of the expenses for improvements made at TEP's power plants. These improvements are necessary to comply with environmental standards required by federal or other governmental agencies.

Typically, the Arizona Corporation Commission (ACC) conducts an annual review of the ECA, approving a rate adjustment that takes effect in May and is used to calculate customer bills for 12 months.

The rate, which is effective from May 1, 2016 through April 30, 2017, will be $0.000250 per kilowatt hour (kWh). For a residential customer with average monthly usage of 800 kWh, this will result in an approximate increase of about 5 cents."

Q. What changes does the Company propose?

A. The Company proposes to modify the ECA by: 1) increasing the cap on annual recovery through the ECA from .25 percent to .50 percent of prior test year revenues to help smooth the rate impacts of compliance with new environmental regulations and 2) converting the cap to a percentage based cap, which will allow for more equitable recovery from all classes.

Q. Putting aside the legal issues surrounding the ECA, what is RUCO's recommendation?

A. The Company has not shown that it has been harmed by the under collection of revenues. Further, any increase in the percentage cap exposes ratepayers to more risk, which has not been compensated by a reduction in the Company's return on equity. RUCO recommends that the current ECA not be modified.

Q. Does your silence on any issue in this rate filing preclude you from addressing these issues in future testimony?

A. No, it does not.

Q. Does this conclude your direct testimony?

A. Yes.

ATTACHMENT A

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 2, 2016

RUCO 7.06

Director and Officers ("D&O") Insurance – Please answer the following questions as they relate to D&O insurance that the Company is seeking to recover in the test year:

a. What is the amount of prepaid D&O insurance included in working capital?

b. Is prepaid D&O insurance included anywhere else in rate base? If so, provide the amount and rate base category.

c. What is the amount of D&O expense recorded in test year operating expenses?

d. In c. above provide the FERC operating expense accounts along with the amounts recorded in each (e.g. administration).

RESPONSE: **April 18, 2016**

TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Rigo Ramirez / Georgia Hale

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: **May 2, 2016**

a. There is $41,658 of D&O insurance included in working capital.

b. No.

c. $50,306. Please see STF 7.18.

d. $50,306 in FERC Account 925.

RESPONDENT:

Rigo Ramirez / Georgia Hale

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.01

Weather Normalization and Customer Annualization – Please break-out the Company's pro-forma adjustment for weather normalization and customer annualization in the amount of negative $(4,791,733) into the following components:

a. The revenue component that is related to weather normalization.

b. The revenue component that is related to customer annualization.

c. The expense component(s) by FERC number that are related to the weather normalization.

d. The expense component(s) by FERC number that are related to the customer annualization.

Further, please break-out these four components by customer class (e.g. residential service, small general service, large general service etc.)

RESPONSE:

a/b. The Company cannot break out the revenue adjustments by each component as requested. The weather normalization and customer annualization calculations are done separately for sales, but there is not a clean separation due to the cross-term, and the revenues are not calculated based on the separate components. See RUCO 7.05 for more details. While an exact separation cannot be done, the $(4,791,733) amount can be clarified some. The Company has a calculated revenue amount based on billed sales and a calculated revenue amount for the total adjusted sales (billed+unbilled+weather normalization+customer annualization). These numbers can be found in the file "Rate Case 2015 TEP Normlzd RevandSalesRedactedVersion-CompSenConf.xlsx" provided in response to UDR 1.001. The difference between the two sets of numbers is $(937,733). That is to say, the combined total of the unbilled sales adjustment, the weather normalized sales adjustment, and the customer annualization adjustment is an adjustment of $(937,733). This can be broken down by class as follows:

	Revenue that belongs to the following adjustments: unbilled sales, weather normalized sales, and customer annualized sales
Residential	(1,199,320)
General Service	1,292,715
Large General Service	(1,284,111)
Large Power Service	227,265
Lighting	25,717
TOTAL COMPANY	(937,733)

Note that no weather normalization is applied to the Large Power Service and Lighting classes. The $(937,773) is the difference between test year billed revenues and the adjusted revenues which include a precise unbilled revenue calculation based on the test year unbilled sales. The remaining $(3,854,000) is the accounting booked unbilled revenue for the test year used simply to gross up to the total booked revenue in the test year.

Please see the file "Rate Case 2015 TEP Normlzd RevandSalesRedactedVersion-CompSenConf.xlsx" provided in response to UDR 1.001 for the detailed breakout of the revenue adjustments by customer classes.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 April 18, 2016

Although the Company cannot separate the revenue impact of the various adjustments, the Company can separate the sales adjustments with the caveat that the customer adjustment includes cross terms from the unbilled and weather adjustments. The table below breaks the sales adjustments out based on the data from above mentioned file.

kWh Sales	Residential (excludes subaccount 5011)	General Service (excludes subaccount 5203)	Large General Service	Large Power Service (includes mining)	Lighting (includes subaccounts 5011 and 5203)	Total
Billed Sales	3,672,758,964	2,126,869,990	1,191,728,770	2,023,064,349	38,616,889	9,053,038,962
Unbilled Sales	3,837,839	6,960,891	(2,189,520)	(1,912,480)	321,271	7,018,000
Customer Adjustment[1]	4,537,296	(161,632)	(14,954,584)	0	1,936	(10,576,983)
Weather Adjustment	(29,391,977)	(1,233,179)	2,905,490	0	0	(27,719,667)
Sales Adjustment	(21,016,842)	5,566,080	(14,238,614)	(1,912,480)	323,207	(31,278,649)
Adjusted Sales	3,651,742,122	2,132,436,070	1,177,490,156	2,021,151,869	38,940,096	9,021,760,313

1 Includes cross terms of unbilled and weather on the customer adjustment

c/d. The expense components are not weather normalized and customer annualized.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.02

Weather Normalization – Please provide the starting year and month and the ending year and month that the Company used to code its data into its model.

RESPONSE:

For purposes of solving for the coefficients used in the weather normalization model, the Company used a fitting period of January 1993 through June 2014. The period represents the entire range of historical UPC data available to the Company.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.03

Weather Normalization – Please provide the results and adjustment to test-year revenue by year under the Company's new model if a nine year, eight year, seven year, six year, five year, four year, and three year model were used. In addition, please provide the statistical outputs, such as p-values and r-squared values associated with each year requested above.

RESPONSE:

The Company objects to the request as it is overly burdensome. The time required to generate each of the models above and to calculate the total adjusted revenue is significant. Please see RUCO 7.05b for an explanation as to why this process is highly burdensome and resource intensive.

For the model statistics of the model the Company used for the weather normalization, please see file RUCO 7.03 TEP Weather Normalization Model Statistics.pdf, Bates Nos. TEP\021852-021889.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.04

Weather Normalization – Please provide the results and adjustment to test-year revenue under the Company's new model if a fifteen year, twenty year, twenty five year and thirty year model were used. In addition, please provide the statistical outputs, such as p-values and r-squared values associated with each year requested above.

RESPONSE:

Please refer to RUCO 7.03.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.05

Weather Normalization – Based on the weather normalization model selected by the Company, please answer the following questions:

a. Please provide the weather normalization equation that the Company used to increase/decrease test year revenues, and supporting documentation, if not already provided.

b. In a brief narrative please explain how the weather normalization equation was used to increase or decrease the different customer classes (e.g. residential).

RESPONSE:

a. There is no single equation that was used by the Company to increase or decrease revenues based on the weather normalization adjustment. Using the calculations provided below, the Company produced a weather normalized sales adjustment (kWh) for the residential, commercial, and small industrial/large general service classes. The weather normalized sales adjustment is split pro-rata from the class level down to the subaccount level. Likewise, the Company takes the class unbilled sales and splits this down to the subaccount level. The Company then estimates sales due to the bill adjustment for each subaccount level. These 3 adjustments are added to the billed sales for the subaccount to arrive at a total adjusted sales amount. It is on this total adjusted sales amount that the adjusted revenue is calculated.

For clarification purposes, total adjusted sales (kWh) are arrived at using the following:

$$\begin{aligned} & Total\ Adjusted\ Sales \\ & \quad = Billed\ Sales + Unbilled\ Sales + Weather\ Adjustment \\ & \quad + Customer\ Annualization\ Sales\ Adjustment. \end{aligned}$$

The weather adjustment component is defined as:

$$Weather\ Adjustment = Actual\ Customers * Weather\ UPC\ Adjustment,$$

where:

$$\begin{aligned} Weather\ UPC\ Adjustment &= \Delta UPC \\ &= ((AveT * T_{ave} + AveTS * T_{ave}^2 + AveTC * T_{ave}^3) \\ &- (AveT * T_{actual} + AveTS * T_{actual}^2 + AveTC * T_{actual}^3)) \\ &+ ((AveDP * DP_{ave} + AveDPS * DP_{ave}^2 + AveDPC * DP_{ave}^3) \\ &- (AveDP * DP_{actual} + AveDPS * DP_{actual}^2 + AveDPC * DP_{actual}^3)) \end{aligned}$$

with:

UPC = Use Per Customer

$AveT$ = Average Temperature coefficient

$AveTS$ = Average Temperature Squared coefficient

$AveTC$ = Average Temperature Cubed coefficient

$AveDP =$ Average Dew Point coefficient

$AveDPS =$ Average Dew Point Squared coefficient

$AveDPC =$ Average Dew Point Cubed coefficient

$T_{ave} =$ 10 year average of average hourly temperature for a month

$T_{actual} =$ Actual average hourly temperature for a month

$DP_{ave} =$ 10 year average of average hourly dew point for a month

$DP_{actual} =$ Actual average hourly dew point for a month.

Running through an example, the residential UPC adjustment for May 2015:

ΔUPC = ((-95.297876*78.892 + 0.7783679*6224.007 + 0*491026.699) - (-95.297876*74.172 + 0.7783679*5501.416 + 0*408048.469)) + ((-5.3743299*25.48 + 0.1156285*649.147 + 0*16539.211) - (-5.3743299*32.284 + 0.1156285*1042.227 + 0*33646.802)).

Which simplifies to:

ΔUPC = ((-2673.709) – (-786.264)) + ((-61.869) – (-52.991)) = 112.555 – 8.878

ΔUPC = 103.677 kWh/customer.

The unrounded UPC adjustment is then applied to the unadjusted customer counts for the month to obtain the weather adjustment for the class. Thus, the weather adjusted sales are defined as:

$$Weather\ Adjusted\ Sales = Billed\ Sales + Unbilled\ Sales\ Adjustment + Actual\ Customers * \Delta UPC.$$

The weather adjustment is then split among the different subaccounts based on the proportion of billed+unbilled sales the subaccount had when compared to the class billed+unbilled sales.

The customer annualization sales adjustment component is:

$$Customer\ Annualization\ Sales\ Adjustment = \frac{Weather\ Adjusted\ Sales}{Bills} * Bills\ Adjustment.$$

Please note that the Customer Annualization Sales Adjustment is done by subaccount instead of by class. Looking at the 5000 Subaccount for May 2015:

$$Customer\ Annualization\ Sales\ Adjustment_{Subaccount\ 5000} = \frac{256{,}821{,}656}{336{,}728} * -637$$
$$= -485{,}805$$

Summing the weather adjusted sales and the customer annualization sales adjustments, the total adjusted sales for subaccount 5000 for May 2015 is 256,335,852 kWh. To see weather adjusted sales and customer annualization adjusted sales for each month for the residential, commercial and small industrial class, refer to the "Residential", "Commercial", and "Industrial" (subaccounts 5300, 5305, and 5322 are also referred to as the small industrial or large general service subaccounts) sheets in the "Rate Case 2015 TEP Normlzd RevandSalesRedactedVersion-CompSenConf.xlsx" file respectively. It is this total adjusted kWh amount that is used to calculate the total adjusted revenue for the month of May for subaccount 5000. This process can be seen by looking at the "5000" sheet in the same file. The total adjusted revenue is calculated from this final Total Adjusted Sales number.

For supporting documentation for the weather normalization model selection process please see the document filed in response to STF1.06 "2015 TEP's Load Forecast Methodology (Final).pdf", pages 8 – 17.

b. Once the total adjusted sales amounts and annualized customer counts are generated, the revenue is calculated based on these amounts. Each billing component is adjusted to reflect these adjustments in total, rather than individually. To illustrate this, consider subaccount 5000 or the standard residential rate. The customer count is annualized, but due to the timing of billing cycles, the bills are adjusted to reflect the ratio of bills to customers based on the annualized customer counts. In addition to the bill ratio, these adjustments must also reflect the single to three phase bill count ratio for single and three phase service. Again, this is performed on a pro-rata basis to reflect the unadjusted actual ratio of single to three phase service. With the sales data, the total adjusted sales must be run through each of the different billing components. Specifically, for subaccount 5000, this includes the seasonal allocation between summer and winter rates and the allocation to the various kWh tiers. The seasonal split was allocated on a pro-rata basis splitting the kWh between winter and summer rates at the same proportion as the actual monthly proportion. The kWh tier allocation was done at the per bill level. Each bill during the month was allocated a proportional adjustment for unbilled and weather adjustments. To allocate customer annualization, adjusted bills were added or subtracted so as to preserve the actual bill frequency distribution for each month and subaccount. A couple of hypothetical examples to illustrate these concepts:

1. A customer had a bill of 500 kWh and their proportional allocation for unbilled and weather for the month was 13 kWh. Thus to calculate their revenue, 500 kWh would be billed in the first tier and 13 kWh billed in the second tier.
2. During this month, say 0.3% of the bills in this subaccount were for 500 kWh, and customer annualization resulted in adding 1000 bills to the subaccount for the month. This means that 3 bills (0.3% * 1000) are added at an adjusted level of 513 kWh. Each of these additional bills adds 500 kWh to the first tier and 13 kWh to the second tier. Note that bills are added (or subtracted) at the adjusted kWh level because if the customer were to have existed (or not existed), these adjustments would need to be added (or subtracted) along with any billed information.

By performing the kWh tier adjustments in this manner, it will most accurately reflect how the weather and unbilled adjustments would change bill frequency. This far more accurate treatment of tier allocations, compared to the historical pro-rata allocation, means that when the sales adjustment changes, so too will the individual bill allocations making this a highly time consuming process to run multiple scenarios.

Many of the other subaccounts have additional adjustments that must be made on a pro-rata basis. Items like time-of-use, demand, and CARES discounts must all be considered. Please see the file "Rate Case 2015 TEP Normlzd RevandSalesRedactedVersion-CompSenConf.xlsx" for the detailed calculations used in the revenue normalization process.
As can be seen in the explanation above, the revenue calculation process for the weather adjusted and customer annualized sales is highly detailed and extensive. Because the unbilled sales, weather adjustment, and customer annualization adjustment are so entwined and the additional complexity required to fully separate their revenue effects would be so burdensome to calculate and check, the company cannot calculate the revenue change caused by each piece individually.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 4, 2016

RUCO 5.1

Credit Card Processing Fees – Please answer the following questions as they relate to Credit Card Processing Fees:

a. In the Company's pro forma adjustment for credit card processing fees, do year 1, year 2, and year 3 refer to 2016, 2017, and 2018? If no, what years do they refer to?

b. In the Company's pro forma adjustment for credit card processing fees, please update the 2015 estimated volume and dollars to actual.

c. In year 1 why does the Company believe credit card usage will increase by 50 percent, 10 percent in year 2, and 10 percent in year 3, or 70 percent overall?

d. Please provide a copy of all contracts between TEP and the credit card vendors.

e. Currently does the Company credit card fee of $3.50 to TEP customers not cover the credit card vendor expenses, TEP has to pay? If no, please provide the amount that is under collected along with the supporting calculations of this amount.

f. How are card paying customers "paying their fair share" if under the Company's proposal non-credit card customers now have to pick-up some of their expenses.

g. How does the Company's proposal not create subsidizes for credit card paying customers at the expense of those that do not pay by credit card?

h. How does the Company's proposal follow cost of service ratemaking (i.e. cost causation)?

i. If the customer has money withdrawn from his/her bank account automatically, does the Company have to pay a fee to the bank?

j. If yes to i., does the Company charge a bank fee to these customers?

RESPONSE:

a. No, they related to 2017, 2018, and 2019.

b. Please refer to the attached Excel file: Income – Credit Card Processing Fees-Revised.xlsm provided in response to UDR 1.001, as supplemented.

c. The increases were based on estimates provided by two independent industry leaders in utility credit card payment processing. It is not a figure calculated by TEP.

According to the research and analysis, utilities who do not charge a convenience fee see double the volume of transactions over those who do charge a fee.

d. The responsive file is competitively sensitive confidential with the ownership of the document held by the contractor. TEP attempted to gain permission to provide the file, but permission was denied.

e. The $3.50 fee represents 100% of the third party transaction costs associated with the credit card payments. The fee is paid directly to the third party vendor by the customer making the payment. TEP does not incur any of these costs.

f. Customers can pay their TEP bill in a number of ways: by check, cash, automatic bank account deduction or credit card. The Company's cost to process these payments varies by type of remittance and its overall processing costs are impacted by customers' behavior. TEP's proposal is in response to consistent feedback from TEP customers indicating dissatisfaction with the high fee that is imposed when paying their bill by credit card. The Company has experienced a growing trend that customers prefer to pay their utility bills by credit cards but realized that customers do not understand why a fee is imposed when other credit card fees for other services are embedded in the market price rather than as an added fee. The cost to Company currently varies by payment method therefore this approach is now more consistent across all customers. The approach still aligns with cost recovery as the credit card customers are still paying $1.00 toward the transaction.

This proposal will create a slight subsidy for customers paying by credit card even though such customers pay a minimal fee. The Company will continue to solicit vendors that will commit to charging a significantly lower fee that will result in less subsidy.

g. Please refer to 5.1(f) above.

h. Please refer to 5.1(f) above.

i. Yes, the depository bank assesses a fee for each withdrawal transaction.

j No, the Company does not.

RESPONDENT:

Brian Bub / Rigo Ramirez

WITNESS:

Denise Smith

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 26, 2016

RUCO 11.14

Wellness Programs - Is the Company seeking recovery of any wellness programs in the test year? If so, please provide the amount adjusted for the ACC jurisdictional ratio.

RESPONSE:

Yes the Company is seeking recovery for the following expenses paid for our Wellness programs in the test year.

- Wellness program administration - Wellness Council of Arizona - $53,133; and
- Wellness Incentive Program – Employees receive an incentive if they obtain an annual physical and lab work. Participation in the program provides employee with either an annual amount of $500 if enrolled in a PPO Medical Plan, or $200 if enrolled in the HDHP Medical plan. The wellness incentive program expense for the test year was $117,642.

RESPONDENT:

Karen Horne / Steve Bracamonte

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 26, 2016

RUCO 11.15

Other Expenses – Have the following expense amounts been adjusted for the ACC jurisdictional ratio?

Lobbying Expenses	$100,421
Employee Recognition	$ 95,557
Spot Awards	$511,250

If no, then what is the ACC jurisdictional amount for each of the above categories?

RESPONSE:

No. ACC jurisdictional amounts for lobbying expenses, employee recognition and spot awards are $353, $59,493 and $318,302 respectively.

Please note that $100,000 of lobbying expense was removed in the Income - Membership Dues.xlsm pro forma adjustment provided in UDR 1.001.

RESPONDENT:

Rigo Ramirez

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 November 13, 2015

UDR 1.034

Incentive Programs. List and describe all retirement and incentive programs available to Company officers and employees. Provide a complete copy of each incentive compensation program and all related materials. Identify the goals and targets in each year 2012-2014, and all evaluations of whether such goals were exceeded. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Incentives:

All TEP non-union employees participate in UNS's short-term incentive program ("PEP"), which is tied to annual compensation.

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2015, the objectives were (i) net income; (ii) managing Long-term O&M; and (iii) excellent operations and safe work environment, which include both quantitative and qualitative measures. The Compensation Committee selected the goals and individual weightings for the 2015 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, and process improvements. This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS's various stakeholders. The outcomes of which all benefit our customers in the long run.

The financial and other metrics for the Company's 2015 Short-Term Incentive Compensation program were:

- Financial – 60%
    - Net Income – 40%
    - Managing Long-term O&M – 20%
- Excellent Operations and Safe Work Environment – 40%

In developing the PEP performance targets, Company management compiles relevant data such as Company historic performance and industry benchmarks and makes recommendations to the Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 9% - 12% for unclassified employees, and 20-25% for senior management level employees. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year. Please see the files listed below for the goals for each year and evaluations of yearly performance.

File Name	Bates Numbers
UDR 1.034 2012-2014 PEP Hist Prcnts-Pos-Confidential.pdf	TEP\015464-015465
UDR 1.034 2012 PEP Goals-Confidential.pdf	TEP\015462-015463
UDR 1.034 2013 PEP Goals-Confidential.pdf	TEP\015466-015467
UDR 1.034 2014 PEP Goals-Confidential.pdf	TEP\015468-015469
UDR 1.034 2015 PEP Goals-Confidential.pdf	TEP\015470-015471

Retirement Programs:

TEP employees are eligible to participate in one of the pension plans for employees of TEP. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR 1.034 TEP_Hourly_Plan_SPD-CONFIDENTIAL.pdf	TEP\015472-015500
UDR 1.034 TEP_Salary_Plan_SPD-CONFIDENTIAL.pdf	TEP\015501-015529

Additionally, TEP employees are eligible to participate in the TEP 401(k) Plan as described below:

401(k) Plan

All employees participate in the TEP's 401(k) Plan, which takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 25% of their pay, before any deduction for state or federal income taxes. The Company matches dollar on dollar, up to 4.5% of pay saved in the 401(k) Plan for TEP employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR 1.034 401K_SPD-CONFIDENTIAL.pdf	TEP\015403-015461

Retirement program expense directly charged or allocated to TEP during each year was as follows:

	2012	2013	2014
TEP SERP Plan (FERC 0426)	$1,004,706	$1,115,118	$954,665
TEP Union and Salaried Pension Plans (FERC 0926)	7,334,904	7,632,836	4,206,860
TEP 401K Plan (FERC 0926)	2,828,818	2,980,758	3,062,120
UNS Electric Pension/401K (FERC 0926)	36,912	44,933	30,874
UNS Gas Pension/401K (FERC 0926)	19,070	21,384	17,007
Deferred Compensation Plan (FERC 0920)	(160,601)	(294,873)	(75,744)

Total	$11,063,809	$11,500,156	$8,195,782

RESPONDENT:

Steve Bracamonte

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 26, 2016

RUCO 11.04

Supplemental Executive Retirement Plan ("SERP") – To clarify is the Company seeking recovery of $1,042,236 of SERP related expenses in this case? If no, then what is the correct amount by FERC account number and adjusted for the ACC jurisdictional ratio?

RESPONSE:

The Company is requesting the following SERP related expenses in this case:

FERC ACCT 926

SERP Expense	$1,129,807
ACC %	83.90774%
ACC Adj. SERP Expense	$947,996

RESPONDENT:

Rigo Ramirez

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 4, 2016

RUCO 5.2

Long-Term Incentive Compensation – Please answer the following questions as they relate to long-term incentive compensation:

a. To clarify the Company is seeking long-term incentive compensation of $1,349,782 in the test year and $1,049,924 as a pro forma adjustment for a total of $2,399,706 in long-term incentive expense in this case. If no please explain.

b. Why did the Company not request long-term incentive compensation in its last rate case?

c. Has the Company in prior rate cases asked for long-term incentive compensation? If so, please provide the docket number, along with the Commission decision relating to the Company's request.

d. Why is the Company using a two year average as opposed to a three year average?

e. What Company executives or officers are eligible for the program?

f. List the names of the executives or officers in d. above along with the total long-term incentive compensation provided to them by fiscal year for the test year and three prior years. The test year and prior year amount should reconcile to your pro forma adjustment.

g. Provide a sub account that breaks-out the long-term compensation amounts between salary and payroll taxes for the years noted in f., the test year and prior year amount should reconcile to your pro forma adjustment.

h. From the Company's pro-forma adjustment $180,098 has been capitalized. Please explain to what accounts this amount was allocated to and how this amount was allocated

i. Was any long-term incentive compensation between 7/1/14 through 12/31/14 capitalized? If so, please provide the amount and explain to what accounts this amount was allocated to and how this amount was allocated.

j. Please explain the Fortis Merger long-term incentive compensation expense offset to the Company's pro-forma adjustment in the amount of $2,534,690, and how it was calculated.

k. Please provide a copy of any and all long-term incentive compensation program document(s), and explain how the performance units and restricted stock units relate to the performance goals, if not already provided.

l. Please provide a copy of the Company's benchmarking study.

m. What is the capitalization percentage for the test year?

RESPONSE:

a. No. While responding to data request AECC 5.1, the Company discovered that the amount listed as Fortis Merger LTI Compensation expense was incorrect. As a result the Pro Forma adjustment was updated accordingly. The Company is seeking long-term incentive compensation of $491,910 in the test year and $1,191,919 as a pro forma adjustment for a total of $1,683,829 in long-term incentive expense in this case

b. Because of the size of the revenue request in the last rate case, the Company decided to not request long-term incentive compensation in this last rate case, but reserved the right to request it in this case.

c. Not in the last two rate cases.

d. The Company used the same two year methodology as it did for the payroll adjustment.

e./f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. The Long-Term Incentive Compensation Pro Forma Adjustment does not include payroll taxes.

h. The $180,098 capitalized amount was allocated to FERC 107 via the A&G Allocation.

i. No long-term incentive compensation between 7/1/14 through 12/31/14 was capitalized.

j. The Fortis Merger triggered the payout of all outstanding long-term incentive awards resulting in the accelerated recognition of compensation expense. Compensation expense on these annual awards is typically recognized ratably over a three-year term. In order to normalize the pro forma adjustment, the amount related to the accelerated recognition of compensation expense as a result of the Fortis Merger was deducted. This amount was calculated as follows:

Total Estimated Additional Comp Expense in 2014	$2,680,890
Multiplied by: TEP Mass. Allocation Percentage	x 80.46%
	2,157,044
Add: Payroll Taxes on LTI Payouts	377,646
	$2,534,690

The Payroll Taxes on LTI Payouts amount listed above should not have been included in the Long-Term Incentive Compensation Pro Forma Adjustment. The pro forma adjustment was subsequently updated in a recent data request as referred to in RUCO 5.2a above.

k. Please see the following attached files:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

File Name	Bates Numbers
RUCO 5.2k - 2012 LTI Term Sheet-Confidential.pdf	TEP\021453-021455
RUCO 5.2k - 2013 LTI Term Sheet-Confidential.pdf	TEP\021456-021459
RUCO 5.2k - 2014 LTI Term Sheet-Confidential.pdf	TEP\021460-021463
RUCO 5.2k - 2015 LTI Term Sheet-Confidential.pdf	TEP\021464-021467

l. TEP is in the process of gathering this information and will provide it as soon as possible.

m. The capitalization percentage used in the Long-Term Incentive Compensation Pro Forma Adjustment for the test year was 24.8% for the period 7/1/14 through 12/31/14 and 26.8% for the period 1/1/15 through 6/30/15.

RESPONDENT:

Georgia Hale/ David Lewis/ Steve Bracamonte

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 26, 2016

RUCO 11.05

Severance Pay Expense – The Company states in UDR 1.043 that it is seeking $365,688 in severance pay expense, has this been adjusted for the ACC jurisdictional ratio? If no, then what is the ACC jurisdictional amount?

RESPONSE:

No. Below is the amount of severance pay expense the Company is seeking:

Account	O&M Severance Pay	ACC Jurisdictional Ratio	ACC Adjusted
FERC 580	$30,000	100.00%	$30,000
FERC 920	223,853	83.90774%	187,830
Total	$253,853		$217,830

$111,835 of severance pay was recorded in FERC 107-Construction Work in Progress, then allocated among various open projects before being capitalized. This portion of severance pay is included in rate base.

RESPONDENT:

Rigo Ramirez

WITNESS:

Frank Marino

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 4, 2016

RUCO 5.4

Rate Case Expense – Please provide the rate case expense authorized by the Commission in the Company's last three rate cases.

RESPONSE:

Please see RUCO 5.4 Prior Rate Case Expense Authorized.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 26, 2016

RUCO 11.03

Rate Case Expense – Please explain the reason why the Company is asking less in rate case expense than it did in its previous rate case ($1,415,000)?

RESPONSE:

In the previous rate case, the Company included a $140,000 Tax Adjustment Study and a $180,000 Generation Decommissioning Study in its estimate of rate case expenses. Since these studies were not performed for the current rate case, no estimated was included in the current request for rate case expenses.

RESPONDENT:

Rigo Ramirez

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-15-0322
Test Year Ended June 30, 2015

TABLE OF CONTENTS TO RUCO's DIRECT SCHEDULES

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-15-0322
Test Year Ended June 30, 2015

Schedule JMM-1

REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 2,104,678	$ 3,721,880	$ 2,913,279	$ 1,840,647	$ 3,323,991	$ 2,582,319
2							
3	Adjusted Operating Income (Loss)	98,381	98,381	98,381	123,680	123,680	123,680
4							
5	Current Rate Of Return (Line 3 / Line 1)	4.67%	2.64%	3.38%	6.72%	3.72%	4.79%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 165,898	$ 165,899	$ 165,900	$ 134,398	$ 134,398	$ 134,398
8							
9	Weighted Average Cost of Capital	7.34%	7.34%	7.34%	6.76%	6.76%	6.76%
10							
11	Fair Value Adjustment	0.54%	-2.88%	-1.65%	0.54%	-2.72%	-1.56%
12							
13	Required Rate of Return	7.88%	4.46%	5.69%	7.30%	4.04%	5.20%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 67,517	$ 67,517	$ 67,517	10,717	10,717	10,717
16							
17	Gross Revenue Conversion Factor (Schedule JMM-2)	1.6223	1.6223	1.6223	1.6223	1.6223	1.6223
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 109,534	$ 109,534	$ 109,534	$ 17,387	$ 17,387	$ 17,387
20							
21	Adjusted Test Year Revenue	$ 941,031	$ 941,031	$ 941,031	$ 941,867	$ 941,867	$ 941,867
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 1,050,566	$ 1,050,566	$ 1,050,565	$ 959,254	$ 959,254	$ 959,254
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	11.64%	11.64%	11.64%	1.85%	1.85%	1.85%
26							
27	Rate Of Return On Common Equity	10.35%	10.35%	10.35%	9.20%	9.20%	9.20%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules JMM-3, JMM-9, and JMM-28
Column (E): Schedule JMM-3, Company Column (F)
Column (F): Average of Column (D) + Column (E) / 2

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-15-0322
Test Year Ended June 30, 2015

Schedule JMM-2

GROSS REVENUE CONVERSION FACTOR, INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A] Company Proposed	[B] RUCO Recommended
1	Gross Revenue	100.00%	100.00%
2			
3	Less: Uncollectible Revenue	0.19%	0.19%
4			
5	Taxable Income as a Percent	99.81%	99.81%
6			
7	Less: Federal and State Income Taxes	38.17%	38.17%
8			
9	Changes in Net Operating Income	61.64%	61.64%
10			
11	Gross Revenue Conversion Factor	1.6223	1.6223

References:
Column [A]: Company as Filed
Column [B]: RUCO Recommended

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-15-0322
Test Year Ended June 30, 2015

RATE BASE (OCRB, RCND and FVRB)
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 3,997,101	$ 7,834,269	$ 5,915,685	196.00%	$ 3,640,860	$ 7,260,771	$ 5,450,815
2	Accumulated Depreciation	(1,582,018)	(3,329,859)	(2,455,939)	210.48%	(1,491,819)	(3,156,261)	(2,324,040)
3	Net Utility Plant In Service	2,415,082	4,504,410	3,459,746		2,149,041	4,104,510	3,126,776
4								
5	Deductions:							
6	Cust. Advances For Const.	(11,046)	(15,465)	(13,255)	140.00%	(11,046)	(15,465)	(13,255)
7	Customer Deposits	(19,400)	(19,400)	(19,400)	100.00%	(19,400)	(19,400)	(19,400)
8	Other (ITC)	(2,631)	(2,631)	(2,631)	100.00%	(2,631)	(2,631)	(2,631)
9	Acc. Deferred Income Taxes	(403,583)	(871,290)	(637,436)	215.89%	(403,583)	(871,290)	(637,436)
10	Total Deductions	(436,660)	(908,786)	(672,723)		(436,660)	(908,786)	(672,723)
11								
12	Allowance - Working Capital	101,143	101,143	101,143	100.00%	103,154	103,154	103,154
13								
14	Regulatory Assets	25,112	25,112	25,112	100.00%	25,112	25,112	25,112
15								
16	Regulatory Liability	-	-	-	100.00%	-	-	-
17								
18								
19	TOTAL TEST YEAR RATE BASE	$ 2,104,678	$ 3,721,880	$ 2,913,279		$ 1,840,647	$ 3,323,991	$ 2,582,319

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule JMM-4, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F) / 2

TUCSON ELECTRIC POWER COMPANY
Docket No. E-01933A-15-0322
Test Year Ended June 30, 2015

Schedule JMM-4

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL (Shown in Thousands)

LINE NO.	DESCRIPTION		(A) COMPANY FILED AS OCRB		(B) RUCO ADJUSTMENTS		(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$	3,997,101		(356,241)	$	3,640,860
2	Accumulated Depreciation		(1,582,018)		90,199		(1,491,819)
3	Net Utility Plant In Service		2,415,082		(266,042)		2,149,041
4							
5	Deductions:						
6	Cust. Advances For Const.	$	(11,046)		-	$	(11,046)
7	Customer Deposits		(19,400)		-		(19,400)
8	Other - Investment Tax Credits ("ITC")		(2,631)		-		(2,631)
9	Accumulated Deferred Income Taxes ("ADIT")		(403,583)		-		(403,583)
10	Total Deductions		(436,660)		-		(436,660)
11							
12	Allowance - Working Capital		101,143		2,011		103,154
13							
14	Regulatory Assets		25,112		-		25,112
15							
16	Regulatory Liability		-		-		-
17							
18							
19	TOTAL OCRB	$	2,104,678	$	(264,030)	$	1,840,647
20							

LINE NO.		Reconciliation to RCND (Thousands of Dollars)				
21						
22			OCRB	RCND Ratio		RCND
23	Company OCRB and RCND as Filed	$	2,104,678		$	3,721,880
24	RUCO Adjustment #1					-
25	Plant		(77,042)	1.0000		(77,042)
26	Accumulated Depreciation		4,466	1.0000		4,466
27	RUCO Adjustment #2					
28	Plant		(67,708)	1.2101		(81,936)
29	Accumulated Depreciation		12,665	1.2109		15,337
30	RUCO Adjustment #3					
31	Plant		(211,491)	1.9600		(414,520)
32	Accumulated Depreciation		73,069	2.1048		153,797
33	RUCO Adjustment #4					
34	Cash Working Allowance		2,011	1.0000		2,011
35	RUCO as Adjusted OCRB and RCND	$	1,840,647		$	3,323,991

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 5
Column (C): Column (A) + Column (B)

TUCSON ELECTRIC POWER COMPANY
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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
(Thousands of Dollars)

		ACC Jurisdiction					
Line No.	DESCRIPTION	(A) Company Adjusted OCRB As Filed	(B) Rate Base Adjustment No. 1 Remove Post-Test Year Plant and Renewables	(C) Rate Base Adjustment No. 2 Market Value TEP Headquarters	(D) Rate Base Adjustment No. 3 Jurisdictional Allocation	(E) Rate Base Adjustment No. 3 Working Capital	(F) RUCO Adjusted OCRB Recommended Balances
1	Gross Utility Plant in Service	$ 3,997,101	$ (77,042)	$ (67,708)	$ (211,491)	$ -	$ 3,640,860
2							
3	Accumulated Depreciation	(1,582,018)	4,466	12,665	73,069	-	$ (1,491,819)
4	Total Net Utility Plant in Service	$ 2,415,082	$ (72,576)	$ (55,043)	$ (138,422)	$ -	$ 2,149,041
5							
6	Customer Advances for Construction	$ (11,046)	$ -	$ -	$ -	$ -	$ (11,046)
7							
8	Customer Deposits	(19,400)					(19,400)
9							
10	Deferred Credit - Contributed Plant	(2,631)					(2,631)
11	and Retirement Obligations						
12							
13	Accumulated Deferred Income Taxes ("ADIT")	(403,583)	-	-	-		(403,583)
14	Total Deductions	$ (436,660)	$ -	$ -	$ -	$ -	$ (436,660)
15							
16							
17	Allowance for Working Capital	$ 101,143	$ -	$ -	$ -	$ 2,011	103,154
18							
19	Regulatory Assets	25,112	-	-	-	-	25,112
20							
21	Regulatory Liabilities	-	-	-	-	-	-
22							
23	Total Original Cost Rate Base						
24		$ 2,104,678	$ (72,576)	$ (55,043)	$ (138,422)	$ 2,011	$ 1,840,647

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See JMM-6
Column (C) See JMM-7
Column (D) See JMM-8
Column (E) See JMM-9
Column (F) See Column (B) through (E)

TUCSON ELECTRIC POWER COMPANY
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Schedule JMM-6

RATE BASE ADJUSTMENT NO. 1
REMOVE POST-TEST YEAR PLANT AND POST-TEST YEAR PLANT - RENEWABLES

Line No.	DESCRIPTION	(A) Company Proposed	(B) RUCO Adjustment	(C) RUCO As Adjusted
1	Gross Utility Plant in Service	$ 3,997,100,696	$ (77,041,806)	$ 3,920,058,890
2	Accumulated Depreciation	(1,582,018,414)	4,465,511	(1,577,552,903)
3	Total Net Utility Plant in Service	$ 2,415,082,282	$ (72,576,295)	$ 2,342,505,987
4				

Line No.		DESCRIPTION	Plant	Acc. Deprec.
5	Post Test Year Plant			
6	303	Miscellaneous intangible plant	$ 13,926,208	$ 1,978,618
7	310	Land and Land Rights	1,526	-
8	311	Structures and improvements	4,884,663	398,599
9	312	Boiler plant equipment	20,403,390	531,927
10	314	Turbo generator units	22,853	1,350
11	315	Accessory electric equipment	1,858,242	228,773
12	344	Generators	1,254,643	30,968
13	360	Land and Land Rights	4,100	58
14	362	Station Equipment	780,364	14,047
15	364	Poles, towers and fixture	5,122,906	102,970
16	365	Overhead conductors and devices	(198,674)	(3,775)
17	366	Underground conduit	27,746	449
18	367	Underground conduit and devices	112,774	2,413
19	368	Line Transformers	1,861,932	39,845
20	369	Services	664,169	14,080
21	370	Meters	695,497	24,760
22	373	Street Lighting	10,727	219
23	390	Structures and improvements General plant	387,061	10,233
24	391	Office furniture and equipment	2,187,377	436,516
25	392	Transportation equipment	325,262	34,594
26	394	Tools, shop, and garage Equip	3,939	232
27	395	Laboratory Equip	51,829	5,050
28	396	Power Operated Equipment	592,513	37,027
29	397	Communication equipment	736,386	46,451
30			$ 55,717,433	$ 3,935,404
31				

Line No.		DESCRIPTION	Plant	Acc. Deprec.
32	Post Test Year Plant - Renewables			
33	312	Boiler plant equipment	$ 4,938,053	$ 82,465
34	344	Generators	16,362,835	447,039
35	397	Communication equipment	23,485	603
36			$ 21,324,373	$ 530,107

Note: Already adjusted for ACC Jurisdictional Ratio

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-7

RATE BASE ADJUSTMENT NO. 2
MARKET VALUE TEP HEADQUARTERS

Line No.	FERC No. DESCRIPTION	(A)[1] Company Proposed	(B) RUCO Adjustment	(C) Company ACC Jurisdictional Ratio	(D) RUCO ACC Jurisdictional Adjusted	(E) RUCO As Adjusted
1	General Plant					
2	389 Land & Rights	$ 8,836,468	$ (8,549,938)	0.8797	$ (7,521,757)	$ 1,314,711
3	390 Structures & Improvements	135,056,114	(68,371,896)	0.8797	(60,149,765)	74,906,348
4	398 Miscellaneous Expense	4,417,241	(41,468)	0.8797	(36,481)	4,380,760
5	Accumulated Depreciation	(22,271,598)	12,665,000	1	12,665,000	(9,606,598)
6	Total Net Utility Plant in Service	$ 126,038,224	$ (64,298,302)		$ (55,043,003)	$ 70,995,221

Note 1: Does not include prior adjustments

References:
Column (A) Per Company Filing
Column (B) Testimony FWR
Column (C) ACC Jurisdictional Ratio
Column (D) = Column (B) * Column (C)
Column (E) = Column (A) + Column (D)

TUCSON ELECTRIC POWER COMPANY
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Schedule JMM-8

RATE BASE ADJUSTMENT NO. 3
JURISDICTIONAL ALLOCATION

		(A)[1]	(B)	(C)
Line No.	DESCRIPTION	Company Proposed	RUCO Adjustment	RUCO As Adjusted
1	Gross Utility Plant in Service	$ 3,997,100,696	$ (211,491,168)	$ 3,785,609,528
2	Accumulated Depreciation	(1,582,018,414)	73,068,841	(1,508,949,573)
3	Total Net Utility Plant in Service	$ 2,415,082,282	$ (138,422,327)	$ 2,276,659,955

Note 1: Does not include prior adjustments

References:
Column (A) Per Company Filing
Column (B) Testimony FWR
Column (C) RUCO as Adjusted

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Schedule JMM-9

RATE BASE ADJUSTMENT NO. 4
ALLOWANCE FOR CASH WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	FERC Number	(A) COMPANY ADUSTED TEST YEAR AS FILED	Adj No.	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days	(E) Exp Lag Days	(F) Net Lag Days	(G) Lead Lag Factor	(H) Cash Working Capital Requirements
1	OPERATING EXPENSES										
2	Non-Cash Expenses:										
3	Bad Debts Expense	904	$ 1,723,975		-	$ 1,723,975	-		-		-
4	Depreciation	403/404	156,891,230	2,13,14	(29,284,312)	127,606,919			-		-
5	Amortization	Multi	2,070,108	12	(80,000)	1,990,108			-		-
6	Deferred Income Taxes	410/411	40,476,449		-	40,476,449			-		-
7	Total Non-Cash Expenses		$ 201,161,762		$ (29,364,312)	$ 171,797,450					-
8											
9	Other Operating Expenses:										
10	Salaries and Wages	Multi	$ 71,355,623	9	(329,665)	$ 71,025,958	38.62	10.46	28.16	0.0772	5,483,204
11	Incentive Compensation	Multi	8,606,720	6,8	(5,187,940)	3,418,780	38.62	259.50	(220.88)	(0.6052)	(2,069,046)
12	Fuel Expense	501/547	301,256,312		-	301,256,312	38.62	28.50	10.12	0.0277	8,344,800
13	Lease Expense	507/501	15,768,836		-	15,768,836	38.62	94.33	(55.71)	(0.1526)	(2,406,324)
14	Remote Generating Plant O&M	Multi	47,732,871	11	(6,046,705)	41,686,166	38.62	(6.90)	45.52	0.1247	5,198,265
15	Office Supplies and Expenses	921	11,750,832	10,14	(1,595,421)	10,155,410	38.62	12.46	26.16	0.0717	728,143
16	Outside Services	923	12,768,854		-	12,768,854	38.62	44.51	(5.89)	(0.0161)	(205,579)
17	Property Insurance	924	2,517,465	14	(932,592)	1,584,872	38.62	-	38.62	0.1058	167,679
18	Injuries and Damages	925	1,677,861	4	(25,153)	1,652,708	38.62	(13.27)	51.89	0.1422	235,015
19	Pensions and Benefits	926	21,130,826	7	(947,996)	20,182,830	38.62	13.03	25.59	0.0701	1,414,816
20	Miscellaneous General Expenses	930	4,700,936	5	(548,924)	4,152,012	38.62	(2.00)	40.62	0.1113	462,119
21	Rents	931	819,229	14	3,887,985	4,707,214	38.62	(40.51)	79.13	0.2168	1,020,524
22	Property Taxes	408	46,931,391	15	(564,897)	46,366,494	38.62	213.43	(174.81)	(0.4789)	(22,204,914)
23	Payroll Taxes	408	10,391,284		-	10,391,284	38.62	15.73	22.89	0.0627	651,533
24	Current Income Taxes	409	-		-	-	38.62	-	38.62	0.1058	-
25	Other Taxes	408	78,937	2,16	681,695	760,632	38.62	91.38	(54.90)	(0.1445)	(109,911)
26	Interest on Customer Deposits	431	31,250		-	31,250	38.62	182.50	(143.88)	(0.3942)	(12,319)
27	Other Operations and Maintenance	Multi	76,989,263	2,3	(13,251,550)	63,737,713	38.62	11.99	26.63	0.0730	4,652,853
28	Total Other Operating Exp.		$ 634,508,489		$ (24,861,165)	$ 609,647,324					
29											
30	Total Operating Expenses		$ 835,670,250		$ (54,225,476)	$ 781,444,774					$ 1,350,860
31											
32	Other Cash Working Capital Elements:										
33	Interest on Long-Term Debt		57,960,902		-	57,960,902	38.62	86.2	(47.58)	(0.1304)	(7,558,102)
34	Rev. Taxes and Assessments		94,388,041		-	94,388,041	38.62	48.16	(9.54)	(0.0261)	(2,463,528)
35											
36			$ 152,348,943		$ -	$ 152,348,943					$ (10,021,630)
37											
38	TOTAL CASH WORKING CAPITAL		$ 988,019,194			$ 933,793,717					$ (8,670,770)
39											

43	Total RUCO	$ (8,670,770)
45	Total Company	$ (10,734,427)
47	Cash Working Capital Adjustment	$ 2,032,083
49	Pre-paid D&O Insurance Adjustment	$ (20,829)
52	Total Adjustment	$ 2,011,254

52 References:
53 Column (A): - Company Schedule B-5
54 Column (B): RUCO Operating Income Adjustments
55 Column (C): Column (A) + (B)
56 Column (D): Company Schedule B-5
57 Column (E): Company Schedule B-5
58 Column (F): Column (D) - Column (E)
59 Column (G): Column (E)/365

TUCSON ELECTRIC POWER COMPANY
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Test Year Ended June 30, 2015

Schedule JMM-10

SUMMARY OF OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D
1	Operating Revenues:			
2	Electric Retail Revenues	$ 909,303	$ 835	$ 910,138
3	Sales for Resale	-	-	-
4	Other Operating Revenue	31,729	-	31,729
5				
6	TOTAL OPERATING REVENUES	941,031	835	941,867
7				
8	Operating Expenses:			
9	Fuel, Purchased Power and Trans	$ 303,925	-	$ 303,925
10	Other Operations and Maintenance Exp	334,931	(24,978)	309,953
11	Depreciation and Amortization	129,703	(29,364)	100,339
12	Taxes Other than Income Taxes	40,735	(1,999)	38,736
13	Income Taxes	33,357	31,878	65,234
14	Rounding Differences	-	-	-
15	TOTAL OPERATING EXPENSES	$ 842,650	(24,464)	$ 818,186
16				
17	OPERATING INCOME (LOSS)	$ 98,381	$ 25,299	$ 123,680

References:
Column (A): Company Schedule C-1
Column (B): RUCO Schedule 10
Column (C): Column (A) + Column (B)

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OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) Adj. 1 Weather Normalization JMM-12	(C) Adj. 2 Jurisdictional Allocation JMM-13	(D) Adj. 3 Reverse Credit Card Fees JMM-14	(E) Adj. 4 Directors & Officers Ins. JMM-15	(F) Adj. 5 Lobbying, Employee, Spot Award JMM-16	(G) Adj. 6 PEP Expense JMM-17
1	Operating Revenues:							
2	Electric Retail Revenues	$ 909,303	$ 835	$ -	$ -	$ -	$ -	$ -
3	Sales for Resale		-	-	-	-	-	-
4	Other Operating Revenue	31,729	-	-	-	-	-	-
5								
6	TOTAL OPERATING REVENUES	941,031	835	-	-	-	-	-
7								
8	Operating Expenses:							
9	Fuel, Purchased Power and Trans	303,925	-	-	-	-	-	-
10	Other Operations and Maintenance Exp	334,931	-	(9,776)	(3,476)	(25)	(549)	(3,667)
11	Depreciation and Amortization	129,703	-	(8,322)	-	-	-	-
12	Taxes Other than Income Taxes	40,735	-	(1,435)	-	-	-	-
13	Income Taxes	33,357	-	8,444	-	-	-	-
14	Rounding Differences	-	-	-	-	-	-	-
15	TOTAL OPERATING EXPENSES	842,650	-	(11,088)	(3,476)	(25)	(549)	(3,667)
16								
17	OPERATING INCOME (LOSS)	$ 98,381	$ 835	$ 11,088	$ 3,476	$ 25	$ 549	$ 3,667

Note: Adjustments 1 - 15 are pre-income tax.

TUCSON ELECTRIC POWER COMPANY
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OPERATING INCOME

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(H) Adj. 7 SERP Expense JMM-18	(I) Adj. 8 Long-Term Incentive JMM-19	(J) Adj. 9 Severance Pay JMM-20	(k) Adj. 10 EEI Dues JMM-21	(L) Adj. 11 Overhaul and Outages JMM-22	(M) Adj. 12 Rate Case Expense JMM-23	(N) Adj. 13 Depreciation Expense JMM-24	(O) Adj. 14 Headquarters Expense JMM-25	(P) Adj. 15 Property Taxes JMM-26
1	Operating Revenues:									
2	Electric Retail Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Sales for Resale	-	-	-	-	-	-	-	-	-
4	Other Operating Revenue	-	-	-	-	-	-	-	-	-
5										
6	TOTAL OPERATING REVENUES	-	-	-	-	-	-	-	-	-
7										
8	Operating Expenses:									
9	Fuel, Purchased Power and Trans	-	-	-	-	-	-	-	-	-
10	Other Operations and Maintenance Exp	(948)	(1,521)	(330)	(204)	(6,047)	-	-	1,564	-
11	Depreciation and Amortization	-	-	-	-	-	(80)	(18,456)	(2,506)	-
12	Taxes Other than Income Taxes	-	-	-	-	-	-	-	-	(565)
13	Income Taxes	-	-	-	-	-	-	-	-	-
14	Rounding Differences	-	-	-	-	-	-	-	-	-
15	TOTAL OPERATING EXPENSES	(948)	(1,521)	(330)	(204)	(6,047)	(80)	(18,456)	(942)	(565)
16										
17	OPERATING INCOME (LOSS)	$ 948	$ 1,521	$ 330	$ 204	$ 6,047	$ 80	$ 18,456	$ 942	$ 565

Note: Adjustments 1 - 15 are pre-income tax.

TUCSON ELECTRIC POWER COMPANY
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OPERATING INCOME OPERATING INCOME STATEMENT - ACC JURISDICTIONAL

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(Q) Adj. 16 Interest Synchronization JMM-27	(R) Adj. 17 Income Tax JMM-28	(S) RUCO as Recommended
1	Operating Revenues:			
2	Electric Retail Revenues	$ -	$ -	$ 910,138
3	Sales for Resale	-	-	-
4	Other Operating Revenue	-	-	31,729
5				
6	TOTAL OPERATING REVENUES	-	-	941,867
7				
8	Operating Expenses:			
9	Fuel, Purchased Power and Trans	-	-	303,925
10	Other Operations and Maintenance Exp	-	-	309,953
11	Depreciation and Amortization	-	-	100,339
12	Taxes Other than Income Taxes		-	38,736
13	Income Taxes	2,116	21,318	65,234
14	Rounding Differences	-	-	-
15	TOTAL OPERATING EXPENSES	2,116	21,318	818,186
16				
17	OPERATING INCOME (LOSS)	$ (2,116)	$ (21,318)	$ 123,680

Note: Adjustments 1 - 15 are pre-income tax.

TUCSON ELECTRIC POWER COMPANY
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Schedule JMM-12

OPERATING INCOME ADJUSTMENT NO. 1
WEATHER NORMALIZAITON

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Electric Retail Revenues	$ 909,302,562	$ 835,322	$ 910,137,884

References:
Column (A) Per Company Filing
Column (B) Testimony FWR
Column (C) = Column (A) + Column (B)

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Schedule JMM-13

OPERATING INCOME ADJUSTMENT NO. 2
JURISDICTIONAL ALLOCATION

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Other Operations and Maintenance Exp	$ 334,931,050	$ (9,776,050)	$ 325,154,999
2	Depreciation and Amortization	129,702,903	(8,321,545)	121,381,358
3	Taxes Other than Income Taxes	40,735,140	(1,434,592)	39,300,547
4	Income Taxes	33,356,599	8,443,904	41,800,503
5	Total Expenses	$ 538,725,691	$ (11,088,283)	$ 527,637,407

References:
Column (A) Per Company Filing
Column (B) Testimony FWR
Column (C) = Column (A) + Column (B)

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Schedule JMM-14

OPERATING INCOME ADJUSTMENT NO. 3
REVERSE CREDIT CARD PROCESSING FEES

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Credit Card Processing Fees	$ 3,475,500	$ (3,475,500)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-15

OPERATING INCOME ADJUSTMENT NO. 4
DIRECTORS AND OFFICERS INSURANCE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Directors and Officers Liability Insurance	$ 50,306	$ (25,153)	$ 25,153
2				
3	RUCO's Calculation:			
4	Company Proposed	$ 50,306		
5	Split between Ratepayers and Shareholder	50%		
6	RUCO Adjustment - Total Company	$ 25,153		

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-16

OPERATING INCOME ADJUSTMENT NO. 5
LOBBYING, EMPLOYEE RECOGNITION, SPOT AWARDS and WELLNESS EXPENSES

		(A)	(B)	(C)
Line No.	DESCRIPTION	COMPANY PROPOSED	RUCO ADJUSTMENT	RUCO AS ADJUSTED
1	Lobbying Expenses	$ 353	$ (353)	$ -
2	Employee Recognition	59,493	(59,493)	-
3	Spot Awards	318,303	(318,303)	-
4	Wellness	170,775	(170,775)	-
5	Total	$ 548,924	$ (548,924)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

TUCSON ELECTRIC POWER COMPANY
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Schedule JMM-17

OPERATING INCOME ADJUSTMENT NO. 6
TEP SHORT-TERM INCENTIVE PROGRAM

Line No.	FERC No.	DESCRIPTION	(A) TEST YEAR COMPANY TOTA	(B) COMPANY PRO FORMA ADJUSTMENT	(C) TOTAL COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) RUCO AS ADJUSTED	(F) ACC JURISDICTIONAL FACTOR	(G) RUCO AS ADJUSTED
1	0500	Steam Prod Oper Supervision	$ 109,412	$ 44,384	$ 153,796	$ (81,300)	$ 72,495	0.8978	$ (72,994)
2	0506	Steam Prod Misc Expense	1,283,253	477,840	1,761,093	(930,892)	830,200	0.8978	(835,781)
3	0514	Steam Prod Mnt Elec Plant	498,759	169,385	668,144	(353,036)	315,109	0.8978	(316,966)
4	0566	Trans Misc Oper Expense	751,760	395,543	1,147,303	(607,015)	540,287	0.0000	-
5	0570	Trans Maint Stn Equip	59,125	39,056	98,181	(52,002)	46,179	0.0000	-
6	0580	Dist Oper Supv & Engr	-	2,298	2,298	(1,234)	1,064	0.9998	(1,234)
7	0588	Dist Misc Expense	370,190	74,524	444,714	(234,701)	210,012	1.0000	(234,703)
8	0598	Dist Maint Misc Plant	93,479	19,546	113,025	(59,653)	53,372	1.0000	(59,652)
9	0903	Cust Rec/Collection Exp	197,685	97,347	295,032	(156,188)	138,845	1.0000	(156,187)
10	0920	A&G Salaries	3,038,685	884,449	3,923,134	(2,071,925)	1,851,209	0.8391	(1,738,505)
11	Total O&M Expense		$ 6,402,348	$ 2,204,372	$ 8,606,720	$ (4,547,947)	$ 4,058,773		$ (3,416,022)
12	0408	Taxes Other Than Inc Tax	527,194	39,006	566,200	(299,106)	267,094	0.8391	(250,972)
13	Total		$ 6,929,542	$ 2,243,378	$ 9,172,920	$ (4,847,053)	$ 4,325,868		$ (3,666,994)
14									
15	Total RUCO adjustment								$ (3,666,994)
16									

Line		7/1/13-6/30/14	7/1/14-6/30/15	2 Yr Average	7/1/14-6/30/15 Test Year	Pro Forma	Total Proposed
17	Company Proposed with 2 percent added onto historical data.						
18							
19		7/1/13-6/30/14	7/1/14-6/30/15	2 Yr Average	7/1/14-6/30/15 Test Year	Pro Forma	Total Proposed
20							
21	040	$ 569,673	$ 562,727	$ 566,200	$ 527,194	$ 39,006	$ 566,200
22	408	-	-	-	-	-	-
23	042	-	-	-	-	-	-
24	050	160,748	146,843	153,796	109,412.00	44,384	153,796
25	050	1,833,265	1,688,920	1,761,093	1,283,253.00	477,840	1,761,093
26	051	679,930	656,358	668,144	498,759.00	169,385	668,144
27	056	1,256,695	1,037,910	1,147,303	751,760.00	395,543	1,147,303
28	057	113,930	82,433	98,181	59,125.00	39,056	98,181
29	058	4,597	-	2,298	-	2,298	2,298
30	058	421,830	467,597	444,714	370,190.00	74,524	444,714
31	059	107,573	118,478	113,025	93,479.00	19,546	113,025
32	090	334,230	255,835	295,032	197,685.00	97,347	295,032
33	092	3,881,602	3,964,666	3,923,134	3,038,685.15	884,449	3,923,134
34							
35		$ 9,364,074	$ 8,981,767	$ 9,172,920	$ 6,929,542	$ 2,243,378	$ 9,172,920
36							

Line		7/1/13-6/30/14	7/1/14-6/30/15	2 Yr Average	7/1/14-6/30/15 Test Year	Pro Forma	Total Proposed	Adjustment
37	Step 1. RUCO removal of the 2 percent increases imbedded in historical costs.							
38								
39		7/1/13-6/30/14	7/1/14-6/30/15	2 Yr Average	7/1/14-6/30/15 Test Year	Pro Forma	Total Proposed	Adjustment
40								
41	040	$ 532,180	$ 536,198	$ 534,189	$ 527,194	$ 6,995	$ 534,189	$ (32,011)
42	408	-	-	-	-	-	-	-
43	042	-	-	-	-	-	-	-
44	050	150,277	139,704	144,990	109,412	35,578	144,990	(8,805)
45	050	1,713,791	1,607,011	1,660,401	1,283,253	377,148	1,660,401	(100,692)
46	051	635,906	624,529	630,217	498,759	131,458	630,217	(37,927)
47	056	1,175,248	985,902	1,080,575	751,760	328,815	1,080,575	(66,728)
48	057	106,455	78,260	92,358	59,125	33,233	92,358	(5,823)
49	058	4,256	-	2,128	-	2,128	2,128	(170)
50	058	394,389	445,661	420,025	370,190	49,835	420,025	(24,689)
51	059	100,584	112,904	106,744	93,479	13,265	106,744	(6,281)
52	090	311,787	243,592	277,689	197,685	80,004	277,689	(17,343)
53	092	3,630,918	3,773,919	3,702,419	3,038,685	663,734	3,702,419	(220,715)
54								
55		$ 8,755,791	$ 8,547,679	$ 8,651,735	$ 6,929,542	$ 1,722,193	$ 8,651,735	$ (521,185)
56								

Line		Total Proposed	Adjustment 50/50 Sharing
57	Step 2. 50/50 Sharing of Short-term Incentive Pay		
58			
59		Total Proposed	Adjustment 50/50 Sharing
60			
61	040	$ 534,189	$ (267,094)
62	408	-	-
63	042	-	-
64	050	144,990	(72,495)
65	050	1,660,401	(830,200)
66	051	630,217	(315,109)
67	056	1,080,575	(540,287)
68	057	92,358	(46,179)
69	058	2,128	(1,064)
70	058	420,025	(210,012)
71	059	106,744	(53,372)
72	090	277,689	(138,845)
73	092	3,702,419	(1,851,209)
74			
75		$ 8,651,735	$ (4,325,868)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-18

OPERATING INCOME ADJUSTMENT NO. 7
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP")

		(A)	(B)	(C)
Line No.	DESCRIPTION	COMPANY PROPOSED	RUCO ADJUSTMENT	RUCO AS ADJUSTED
1	Supplemental Executive Retirement Plan	$ 947,996	$ (947,996)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-19

OPERATING INCOME ADJUSTMENT NO. 8
TEP LONG-TERM INCENTIVE PROGRAM

Line No.	FERC No.	DESCRIPTION	(A) Test Year Company Total	(B) Company Pro Forma Adjustment	(C) Total COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) ACC Jurisdictional Factor	(F) RUCO AS ADJUSTED
1	0920	A&G Salaries	$ 491,910	$ 1,191,919	$ 1,683,829	$ (1,683,829)	0.8391	$ (1,412,862)
2								
3	Effective Payroll Tax Rate 7.65 Percent		37,631	91,182	128,813	(128,813)	0.8391	(108,084)
4								
5	Total		$ 529,541	$ 1,283,101	$ 1,812,642	$ (1,812,642)		$ (1,520,946)
6								
7	Note:							
8	(1) FERC account 0920 already netted against the 25.8 percent capitalization rate.							
9	(2) This adjustment reverses the original Company Pro Froma Adjustment of $1,049,924.							

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-20

OPERATING INCOME ADJUSTMENT NO. 9
SEVERANCE PAY

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Severance Pay	$ 329,665	$ (329,665)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-21

OPERATING INCOME ADJUSTMENT NO. 10
EEI DUES

Line No.	DESCRIPTION	(A) TEST YEAR AMOUNT	(B) COMPANY ADJUSTMENT	(C) COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) RUCO ACC JURISDICTIONAL RATIO	(F) RUCO AS ADJUSTED
1	EEI Membership - USWAG	$ 422,845	$ (67,655)	$ 355,190	$ (143,767)	0.8391	$ (138,060)
2	EEI Industry Issues	39,044	(11,713)	27,331	(7,809)	0.8391	
3	Contribution to The Edison Foundation	15,000	-	15,000	(7,500)	0.8391	(6,293)
4	Avian Power Line	2,500	-	2,500	(1,250)	0.8391	(1,049)
5	UARG - Membership Dues	140,309	-	140,309	(70,155)	0.8391	(58,865)
6	Total Dues Expense	$ 619,698	$ (79,368)	$ 540,330	$ (230,481)		$ (204,267)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-22

OPERATING INCOME ADJUSTMENT NO. 11
OVERHAUL AND OUTAGE

LINE NO.		(A) TEP AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ACC Jurisdictional Factor	(E) RUCO AS ADJUSTED
1	Expenditures by Plant Location					
2	Four Corners					
3	Estimated recurring expense	$ 2,700,063	$ (2,238,572)	$ 461,491		
4	Actual test year expenditures	-	-	-		
5	Adjustment	2,700,063	(2,238,572)	461,491	95.66%	$ (2,141,386)
6						
7	Navajo					
8	Estimated recurring expense	1,384,559	(474,604)	909,955		
9	Actual test year expenditures	2,561,527	-	2,561,527		
10	Adjustment	(1,176,968)	(474,604)	(1,651,572)	95.66%	$ (454,000)
11						
12	San Juan					
13	Estimated recurring expense	2,188,235	5,400	2,193,635		
14	Actual test year expenditures	4,464,000	-	4,464,000		
15	Adjustment	(2,275,765)	5,400	(2,270,365)	95.66%	$ 5,166
16						
17	Luna					
18	Estimated recurring expense	944,201	(546,061)	398,140		
19	Actual test year expenditures	1,185,383	-	1,185,383		
20	Adjustment	(241,182)	(546,061)	(787,243)	95.66%	$ (522,354)
21						
22	Gila					
23	Estimated recurring expense	641,176	(641,176)	-		
24	Actual test year expenditures	232,778	-	232,778		
25	Adjustment	408,398	(641,176)	(232,778)	95.66%	$ (613,340)
26						
27	Springerville					
28	Estimated recurring expense	3,419,588	(972,349)	2,447,239		
29	Actual test year expenditures	-	-	-		
30	Adjustment	3,419,588	(972,349)	2,447,239	95.66%	$ (930,135)
31						
32	Sundt / Irvington					
33	Estimated recurring expense	2,544,412	(1,121,768)	1,422,644		
34	Actual test year expenditures	-	-	-		
35	Adjustment	2,544,412	(1,121,768)	1,422,644	95.66%	$ (1,073,067)
36						
37	ICT					
38	Estimated recurring expense	626,471	(332,004)	294,467		
39	Actual test year expenditures	-	-	-		
40	Adjustment	626,471	(332,004)	294,467	95.66%	$ (317,590)
41						
42	Net Estimated Recurring Expenses	14,448,705	(6,321,134)	8,127,571		
43	Net Test Year Expenditures	8,443,688	-	8,443,688		
44						
45	COMPANY ADJUSTMENT	$ 6,005,017	$ (6,321,134)	$ (316,117)	95.66%	(6,046,705)
46						
47	RUCO ADJUSTMENT					
48						
49	RUCO ADJUSTMENT - ACC JURISDICTIONAL					$ (6,046,705)
50						
51	The Company project their average estimated recurring expense from 2016 through 2024.					
52	RUCO removed the projected average and instead used a historical average based on known and measureable costs.					

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)
Column (D) = ACC Jurisdictional Ratio
Column (E) = RUCO ACC Jurisdictional

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Schedule JMM-23

OPERATING INCOME ADJUSTMENT NO. 12
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense	$ 1,190,000	$ (240,000)	$ 950,000
2	Normalization Years	3	3	3
3	Rate Case Expense	$ 396,667	$ (80,000)	$ 316,667

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-24

OPERATING INCOME ADJUSTMENT NO. 13
DEPRECIATION EXPENSE

Line No.		DESCRIPTION		(A) COMPANY PROPOSED		(B) RUCO ADJUSTMENT		(C) RUCO AS ADJUSTED
1		Depreciation and Amortization	$	129,702,903	$	(18,456,271)	$	111,246,631
2								
3	Remove Post Test Year Plant			Plant		Depreciation Rate		Deprec. Exp
4	303	Miscellaneous intangible plant	$	13,926,208		0.2842	$	3,957,236
5	310	Land and Land Rights		1,526		-		-
6	311	Structures and improvements		4,884,663		0.1632		797,198
7	312	Boiler plant equipment		20,403,390		0.0521		1,063,854
8	314	Turbo generator units		22,853		0.1181		2,700
9	315	Accessory electric equipment		1,858,242		0.2462		457,546
10	344	Generators		1,254,643		0.0494		61,936
11	360	Land and Land Rights		4,100		0.0283		116
12	362	Station Equipment		780,364		0.0360		28,094
13	364	Poles, towers and fixture		5,122,906		0.0402		205,940
14	365	Overhead conductors and devices		(198,674)		0.0380		(7,550)
15	366	Underground conduit		27,746		0.0324		898
16	367	Underground conduit and devices		112,774		0.0428		4,826
17	368	Line Transformers		1,861,932		0.0428		79,690
18	369	Services		664,169		0.0424		28,160
19	370	Meters		695,497		0.0712		49,520
20	373	Street Lighting		10,727		0.0408		438
21	390	Structures and improvements General plant		387,061		0.0529		20,466
22	391	Office furniture and equipment		2,187,377		0.3991		873,032
23	392	Transportation equipment		325,262		0.2127		69,188
24	394	Tools, shop, and garage Equip		3,939		0.1178		464
25	395	Laboratory Equip		51,829		0.1949		10,100
26	396	Power Operated Equipment		592,513		0.1250		74,054
27	397	Communication equipment		736,386		0.1262		92,902
28			$	55,717,433			$	7,870,808
29								
30	Remove Post Test Year Plant - Renewables			Plant				
31	312	Boiler plant equipment	$	4,938,053		0.0334	$	164,930.00
32	344	Generators		16,362,835		0.0546		894,078
33	397	Communication equipment		23,485		0.0514		1,206
34			$	21,324,373			$	1,060,214
35								
36	Adjust Depreciation Expense for San Juan Unit 1 and Springerville in total							
37				Company		RUCO		Deprec. Exp
38	San Juan Unit 1		$	18,127,762	$	10,629,652	$	7,498,110
39								
40	Springerville Total		$	27,058,363	$	23,947,259	$	3,111,104
41								
42	ACC Jurisdictional Ratio							0.8978
43	Total Deprecation Study Adjustment						$	9,525,249

Note: Already adjusted Post Test Year Plant for ACC Jurisdictional Ratio

References:
Column (A) Per Company Filing
Column (B) Testimony FWR
Column (C) = Column (A) + Column (B)

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Schedule JMM-25

OPERATING INCOME ADJUSTMENT NO. 14
DEPRECIATION EXPENSE AND OTHER EXPENSES ASSOCIATED WITH TEP HEADQUARTERS

Line No.	FERC No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) Company ACC Jurisdictional Ratio	(D) RUCO ACC Jurisdictional Adjusted	(E) RUCO As Adjusted
1	921	Office Supplies & Expenses	$ 15,081,126	$ (1,657,958)	0.8391	$ (1,391,155)	$ 13,689,971
2	924	Property Insurance	4,269,229	(1,111,450)	0.8391	(932,592)	3,336,636
3	931	Rents	822,856	4,633,644	0.8391	3,887,985	4,710,841
4	890	Depreciation Expense	3,508,569	(3,023,648)	0.8290	(2,506,495)	1,002,073
5		Total	$ 23,681,779	$ (1,159,412)		$ (942,257)	$ 22,739,522

References:
Column (A) Per Company Filing
Column (B) Testimony FWR
Column (C) ACC Jurisdictional Ratio
Column (D) = Column (B) * Column (C)
Column (E) = Column (A) + Column (D)

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Schedule JMM-26

OPERATING INCOME ADJUSTMENT NO. 15
REMOVE POST TEST YEAR PROPERTY TAX EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Property Tax	$ 564,897	$ (564,897)	$ -
2				
3	Post Test Year Property Tax			
4	Generation:			
5	Post Test Year Plant	$ 159,010		
6	Post Test Year Plant - Renewables	58,378		
7	Distribution:			
8	Post Test Year Plant	243,625		
9	Post Test Year Plant - Renewables	-		
10	General:			
11	Post Test Year Plant	103,744		
12	Post Test Year Plant - Renewables	140		
13	Total	$ 564,897		

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-27

Operating Adjustment No. 16
Interest Synchronization

Line No.	Description	Tax Rate	(A) Company Proposed	(B) RUCO Recommended
1	Adjusted Rate Base		$ 2,104,677,690	$1,840,647,319
2	Weighted Cost of Debt		2.16%	2.16%
3	Synchronized Interest Deduction		$ 45,461,038	$ 39,757,982
4	Increase (Decrease) in Deductible Interest			$ (5,703,056)
5	State Income Taxes	3.24%		$ 184,950
6	Federal Taxable Income			$ (5,518,106)
7	Federal Income Taxes	35.00%		$ 1,931,337
8	Increase (Decrease) to Income Tax Expense			$ 2,116,287

References:
Column (A) Per Company Filing
Column (B) Testimony JMM

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Schedule JMM-28

OPERATING INCOME ADJUSTMENT NO. 17
INCOME TAX EXPENSE

Line No.	RUCO Income Tax Calculation on RUCO Adjustments (Thousands of Dollars)		
1	Operating Revenues:		
2	Electric Retail Revenues	$	835,322
3	Sales for Resale		-
4	Other Operating Revenue		-
5	Total Operating Revenue	$	835,322
6			
7	Operating Expenses:		
8	Fuel, Purchased Power and Trans	$	-
9	Other Operations and Maintenance Exp		(24,977,963)
10	Depreciation and Amortization		(29,364,312)
11	Taxes Other than Income Taxes		(564,897)
12	Pre -Tax Operating Expenses	$	(54,907,171)
13	Pre -Tax Operating Income	$	55,742,493
14	Income Taxes	$	21,317,602
	Combined Effective Tax Rate from Company's C-3		38.2430%

References:
Testimony JMM

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Schedule JMM-29

COST OF CAPITAL - ORIGINAL COST RATE BASE
Thousands of Dollars

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Long-term Debt	1,441,656	-	1,441,656	49.97%	4.32%	2.16%
2							
3	Common Equity	1,443,610	-	1,443,610	50.03%	10.35%	5.18%
4							
5	TOTAL CAPITAL	$ 2,885,266	$ -	$ 2,885,266	100.00%		
6							
7	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.34%
8							
9							

10 COST OF CAPITAL - FAIR VAUE RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
16							
17	Long-term Debt	1,441,656	$ -	$ 1,441,656	49.97%	4.32%	2.16%
18							
19	Common Equity	1,443,610	-	1,443,610	50.03%	9.20%	4.60%
20							
21	TOTAL CAPITAL	$ 2,885,266	$ -	$ 2,885,266	100.00%		
22							
23	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						6.76%
24							
25							
26						Fair Value Increment	0.54%

References:
- Column (A): Company Schedule D-1
- Column (B): Testimony, RBM
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital
- Column (E): Testimony, RBM
- Column (F): Column (D) X Column (E)

EXHIBIT
RUCO
5
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. W-01933A-15-0322

SURREBUTTAL TESTIMONY AND

SETTLEMENT TESTIMONY

OF

JEFFREY MICHLIK

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 25, 2016

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ATTACHMENTS

EXECUTIVE SUMMARY

The Residential Utility Consumer Office ("RUCO") has reviewed the rebuttal testimony of Tucson Electric Power Company ("Company or TEP"), and the direct testimony of Commission Staff ("Staff") and the various interveners in this docket.

The testimony herein, discusses RUCO's settlement of issues related to the revenue requirement and issues that are still outstanding.

I. INTRODUCTION

Q. Please state your name for the record.

A. My name is Jeffrey M. Michlik.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on June 3, 2016.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the revenue requirement, and other issues.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony is presented in three sections. Section I provides an introduction. Section II addresses the settlement of the revenue requirement by several parties in this case, and Section III addresses other issues.

II. SETTLEMENT OF REVENUE REQUIREMENT

Q. Did the Company, Staff, RUCO and several other intervenors meet with the Company in settlement negotiations to try to narrow and settle issues relating to the revenue requirement in this case?

A. Yes. The parties in this proceeding met with the Company on Friday August the 6th.

Q. What were the results of the settlement meeting?

A. Some parties including RUCO have settled on a revenue requirement of $81,497,921, see attachment A.

Q. Please highlight some of the major areas that the Company, RUCO and other parties in this proceeding were able to reach agreement.

A. While I will not address every issue reached in the settlement agreement just those dealing with revenue requirement, I will go over some of the major points in the settlement agreement that benefit ratepayers that relate to settled revenue requirement. The Company, RUCO and other parties to the settlement have agreed to:

- A permanent write down of the Net Book Value of the TEP headquarters by $5 million which results in a $5 million dollar reduction to Original Cost Rate Base. This will resolve the TEP headquarters issue that was an issue in the last rate case, and in this rate case, and going forward.

- The inclusion of post-test year plant that was in service as of June 30, 2016 in the amount of $49.6 million, and post-test year renewable generation plant in the amount of $4.8 million. Which is a reduction of $18.1 million[1] from what the Company requested in Rebuttal testimony.

[1] See Company Rebuttal Schedule B-2, Page 2 of 5.

- As laid out in Attachment A, the following changes to depreciation and amortization rates were negotiated by the parties that were previously in dispute:
  - (i) that the rates for San Juan Generating Station shall be adjusted to reflect a depreciable life of TEP's total investment, including the Balanced Draft project, at San Juan Unit 1 of six (6) years;
  - (ii) $90 million of excess distribution reserves will be transferred to San Juan Unit 1 and
  - (iii) a change to depreciation rates on TEP's distribution plant to offset the change in depreciation expense for San Juan Unit.

- Additional provisions include the following:
  - (i) A six year historical average of outage expenses.
  - (ii) Exclusion of 2017 payroll expense of 2 percent related to non-classified employees.
  - (iii) A 50/50 sharing of short-term incentive compensation.
  - (iv) Rate case expense of $1 million normalized over four years, and
  - (v) Removal of $1.1 million associated with litigation costs related to Alterna.

Q. Any other comments on the settled revenue requirement of $81,497,921?

A. Yes. $15,243,913 of revenue requirement increase is related to the non-fuel operating costs associated with the Company's 50.5 percent share of

Springerville Generating Station ("SGS") Unit 1. The Company in its direct testimony requested that this amount be passed through the Purchased Power and Fuel Adjustment Clause ("PPFAC"). Since that time the Company now owns 100 percent of SGS Unit 1, the Company has asked that the $15,243,913 be included in operating expenses, and removed from the PPFAC. Stated another way the ratepayers would have to pay for this either through the PPFAC or through base rates, and thus any perception that RUCO has agreed to an additional increase of $15,243,913 is untrue.

III. OTHER ISSUES

Q. Are there any remaining issues that you testified to in direct testimony that were not settled?

A. Yes. The expansion of the adjustor mechanisms and the Company's weather normalization.

Expansion of Current Adjustor Mechanisms

Q. You discussed the Company's expansion of their current Adjustor Mechanisms in direct testimony?

A. Yes.

Q. Do you have anything new to add?

A. Yes, just briefly. The recommended order and opinion issued by the administrative law judge in Docket No. E-04204A-15-0142, addressed the Lost Fixed Cost Recovery ("LFCR") Mechanism. "UNSE has not met its burden to show that its proposed changes to the LFCR mechanism are in the public interest. The LFCR mechanism is not intended to operate as a full De-coupler mechanism, but rather to collect the lost fixed cost revenues associated with Commission-mandated programs such as Energy Efficiency and DG." [2]

Similarly, regarding the Purchased Power and Fuel Adjustment Clause ("PPFAC"). "The Company has not presented a compelling reason for changing the current method of allocating fuel costs among the various rate classes in the PPFAC. Therefore, for the reasons set forth by Staff and RUCO, we decline to adopt UNSEE's proposed PPFAC modifications".[3]

Weather Normalization

Q. In your direct testimony RUCO recommended that the Company file an annual report that showed the impact of weather normalization on the Company's revenue?

A. Yes.

Q. What was the Company's response?

A. The Company in its rebuttal testimony stated that it could file the annual report, but it would be time consuming, and would seek recovery from the ratepayers of any costs incurred to provide this information.

Q. What is RUCO's response?

A. RUCO will withdraw the request at this time, but this does not preclude RUCO from revisiting this issue in the next rate case.

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[2] See page 123, line 2.
[3] See page 118, line 18.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ATTACHMENT A

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	-	
Rate Base Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	(32,996,491)	(32,996,491)	(32,996,491)	Impact of change to jurisdictional allocations except for impacts to rate base adjustments listed below
SGS CHF	(41,966,722)	(41,239,083)	(41,239,083)	727,640	Impact of change to jurisdictional allocations
Fortis Merger Rate Base Adjustment	(522,398)	(517,560)	(517,560)	4,838	Impact of change to jurisdictional allocations
Asset Retirement Obligation	-	-	-	-	
Post Test Year Plant	51,782,029	51,003,979	49,627,152	(2,154,877)	Settlement Position - Exclude plant not in service prior to June 2016
Post Test Year Plant - Renewables	20,794,266	20,433,724	4,815,398	(15,978,868)	Settlement Position - Exclude plant not in service prior to June 2016
Delayed Unitization	13,237,543	13,118,186	13,118,186	(119,357)	Impact of change to jurisdictional allocations
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(57,662,694)	(53,460,485)	4,848,201	Impact of change to jurisdictional allocations and conforming changes
ADIT - Extension of Bonus Depreciation	-	(12,672,205)	(12,673,409)	(12,673,409)	ADIT related to extension of bonus depreciation
San Juan Unit 2	-	(0)	-	-	
Sundt Coal Handling facilities	(19,120)	(18,789)	(18,789)	331	Impact of change to jurisdictional allocations
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,736,607	6,736,607	(118,864)	Impact of change to jurisdictional allocations
SGS Leashold Amortization Roll Forward	-	-	(3,582,976)	(3,582,976)	
Sundt & San Juan M&S	1,225,594	1,956,711	1,956,711	731,117	Increase is do to the revision of obsolete inventory at Sundt
Head Quarters	-	-	(4,322,455)	(4,322,455)	Settlement Position - $5M Write-down of TEP's investment in the HQ building
Working Capital	(27,325,154)	(20,740,139)	(21,164,215)	6,160,939	Impact of changes to pro forma adjustments.
Accumulated Depreciation adj and LTI	-	-	-	-	
Total Adjustments	(3,905,553)	(42,256,127)	(63,379,783)	(59,474,230)	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Pro Forma OCRB	2,104,677,690	2,066,327,116	2,045,203,460		
Proposed Rate of Return	7.34%	7.16%	7.04%		
Required Operating Income OCRB	$154,416,180	$147,984,232	$143,913,380		
Fair Value Increment of Rate Base	$808,601,055	791,549,067	798,782,394		
Fair Value Rate Base (FVRB)	$2,913,278,745	$2,857,875,183	$2,843,985,854		
Proposed FVROR	5.69%	5.57%	5.34%		
Required Operating Income on FVRB	165,888,315	159,224,227	151,901,204		
Implied ROR on Fair Value Increment of Rate Base	1.42%	1.42%	1.00%		
Original Operating Income - Unadjusted	$318,271,141	$318,271,141	$318,271,141		
<u>Operating Income Adjustments</u>					
<u>Operating Revenue Adjustments</u>					
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	-	
Revenue Reduction Industrial Customer Curtailment			(4,579,770)	(4,579,770)	This reflects the five million dollar write-down to the Headquarters Building per ACC Jurisdiction.
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(4,791,733)	(4,791,733)	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Base Cost of Fuel & Purchased Power	(17,815,595)	(32,594,041)	(32,594,041)	(14,778,446)	Variance is due to a decrease in kWh sales (from 9.021M to 8,881M) and a decrease in the proposed PPFAC rate (from 3.3692 to 3.2559).
Miscellaneous Service Revenue	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	250,000	-	
Total Adjustments to Operating Revenues	(195,448,418)	(210,226,864)	(214,806,634)	(19,358,216)	
Operating Expense Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	(2,619,840)	(2,619,840)	(2,619,840)	Impact of change to jurisdictional allocations except for impacts to operating expense adjustments listed below.
REST and DSM	(19,891,996)	(19,769,956)	(19,769,956)	122,040	Impact of change to jurisdictional allocations
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,663,540)	(1,663,540)	32,881	Impact of change to jurisdictional allocations
Springerville Units 3 & 4	(84,382,546)	(83,129,337)	(83,129,337)	1,253,210	Impact of change to jurisdictional allocations
Sales of SO2 Allowances	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(276,646)	(276,646)	1,429	Impact of change to jurisdictional allocations
Base Cost of Fuel & Purchased Power	226,811,827	212,033,380	212,033,380	(14,778,447)	See explanation in Operating Revenues section.
Gila River O&M	6,130,964	6,024,663	6,024,663	(106,301)	Impact of change to jurisdictional allocations
Springerville Unit 1	(11,558,130)	(11,384,664)	(11,384,664)	173,466	Impact of change to jurisdictional allocations
SGS Unit 1 Non Fuel O&M (50.5% Share)	-	15,243,913	15,243,913	15,243,913	Addition of non-fuel operating costs associated with the 50.5% share of SGS Unit 1.
Overhaul & Outage Normalization	5,176,492	5,644,715	4,889,841	(286,651)	Settlement Position - To reflect a six year historical average outage expense.
Payroll Expense	2,264,794	2,250,757	1,657,361	(607,433)	Settlement Position - To exclude the 2017 2% payroll increase related to Non-Classified employees.
Payroll Tax Expense	151,051	151,051	111,227	(39,824)	
Pension & Benefits	2,004,436	1,576,055	1,576,055	(428,381)	Removed SERP expense as proposed by Staff and RUCO.
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	-	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP As Filed	TEP Rebuttal	Settlement	Total Difference	Explanation of TEP Revisions
Short-Term Incentive Compensation	702,980	1,578,745	(1,932,314)	(2,635,274)	Settlement Position - To reflect a 50/50 sharing between company and rate payer.
Rate Case Expense	107,834	107,834	(15,231)	(123,065)	Settlement Position - To reflect $1M normalized over 4 years
Injuries and Damages	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(212,690)	(212,690)	6	Impact of change to jurisdictional allocations
Bad Debt Expense	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,869,457)	(3,869,457)	52,230	Impact of change to jurisdictional allocations
Long Term Incentive Compensation	880,967	-	-	(880,967)	Remove long term incentive compensation as proposed by Staff.
Depr. & Amort. Expense	9,253,715	1,542,840	1,542,839	(7,710,876)	Decrease is due to removal of 2% inflation for dismantlement costs, and a -5% future net salvage value for distribution assets.
Post Test Year Plant Depreciation and Amortization	-	4,568,108	4,099,163	4,099,163	Settlement Position - To reflect the impact of Post Test year plant exclusions.
Sundt & San Juan M&S	408,531	652,237	652,237	243,706	Increase is due to an increase in obsolete Sundt coal handling inventory.
Property Tax Expense	3,119,696	3,119,770	3,119,770	74	Impact of change to jurisdictional allocations
Asset Retirement Obligation	(393,590)	(386,765)	(386,765)	6,825	Impact of change to jurisdictional allocations
SGS Common Facilities Lease	(1,195,980)	(1,175,244)	(1,175,244)	20,736	Impact of change to jurisdictional allocations
San Juan Unit 1 SCNR O&M	955,223	938,661	938,661	(16,562)	Impact of change to jurisdictional allocations
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	-	
Lime Expense		(1,612,486)	(1,612,486)	(1,612,486)	Company removed lime expense included in test year related to our jointly owned facility. These costs are recovered in base cost of fuel
TEP Headquarters - Write Down	-	-	(109,155)	(109,155)	Settlement Position - $5M Write-down of TEP's investment in the HQ building
Outside Legal Expense			(1,124,730)	(1,124,730)	Settlement Position - To reflect the removal of litigation cost with Alterna.
Credit Card Processing Fees	3,475,500	-	-	(3,475,500)	Removed credit card processing fees as proposed by Staff and RUCO.
Income Tax Expense	(16,130,352)	(19,049,439)	(17,595,211)	(1,564,859)	Conforming changes

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

ATTACHMENT A TO SETTLEMENT AGREEMENT

	TEP	TEP		Total	
	As Filed	Rebuttal	Settlement	Difference	Explanation of TEP Revisions
Transmission Expense Adjustment	95,464,952	93,719,409	90,043,670	(5,421,282)	Decrease in transmission expense reflects the impact of a usage reduction related to one of the Company's largest customers.
D&O Insurance	-	(21,105)	(21,105)	(21,105)	Accepted 50/50 sharing as proposed by RUCO and Staff.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	-		-	
Severance Pay	-	(329,665)	(329,665)	(329,665)	Removed severance pay as proposed by RUCO.
Total Adjustments to Operating Expense	24,441,665	10,845,501	1,798,941	(22,642,724)	
Total Net Adjustments	(219,890,083)	(221,072,365)	(216,605,575)		
Adjusted Operating Income	$98,381,058	$97,198,776	$101,665,566		
Operating Income Deficiency	$67,517,257	$62,025,451	$50,235,638		
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223		
Increase in Gross Revenue Requirement	$109,534,118	$100,624,690	$81,497,921		

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322 et al.

REDACTED DIRECT TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 3, 2016

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EXECUTIVE SUMMARY

The Company's presentation is a study in contrasts. On the one hand, Company President David Hutchens testified that the impact of EE and DG on the Company's retail electric sales has been significant noting that energy efficiency and distributed generation reached nearly 1,000,000 MWh, which equates to about 11% of TEP's test year sales. On the other hand, the Company has acquired 413 MW of Gila River Unit #3 and in 2015, the Company's growing renewable energy portfolio (including DG) is expected to expand to over 500 megawatts as compared to 56 MW in the Company's last rate proceeding.

On the one hand the Company has been told that its load forecasts appear to be optimistic in that is assumes a rapid return to historical load growth and the ACC Staff recommended that TEP reexamine their load forecasting techniques. Yet, Company President David Hutchens states that from the period of January 1, 2012 to June 30, 2015, TEP invested approximately $1.3 billion in order to continue providing its customers with safe and reliable service. On a net plant basis for retail customers these investments increase rate base from $1.5 billion in the last case to $2.1 billion in this case an increase of 40%. The Company does not seem to understand its building for load that under current market conditions is unlikely to return.

The Company is asking for a large amount of outstanding issues to be addressed in this case and the cost of them is large. Gila River Unit 3 is being placed in rate base. The Company wants to recover the increased cost for Springerville Unit 1 in the fuel adjustment clause. The Company seeks full cost recovery of the stranded assets related to the Sundt Coal Handling facilities and the pending retirement of San Juan Unit 2. The Company seeks to shorten the service life of San Juan Unit 1 because of problems that may or may not occur almost a decade from now.

I propose a series of adjustments to the Company's presentation. The first addresses the capacity acquisition issue. When the Company has excess capacity, it sells it in the wholesale market to recover some of the costs for supporting that capacity. This is done under FERC approved wholesale power contracts. The Company's presentation removes some of the sales unjustly and I propose an adjustment which is more reflective of conditions that occurred in the test year and appear likely to reoccur in the year following when rates are reset, 2017.

My second adjustment is to depreciation. Here I propose two adjustments. The first is to reject the shortening of the service life for San Juan Unit 1. The Company has no firm basis to make this adjustment and given the rate impact, an almost $13 increase in depreciation expense, and the fact that the Company is asking ratepayers to pay for so many other things in this case, I believe the Company's proposed shortening of the service life is premature.

My third adjustment relates to the recovery of post-test year plant. Based on past precedent in this State, post-test year plant might be allowed for recovery in rates when the plant is necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making. This Company has a history of being overly optimistic in its load projections and has been asked to review this by Commission Staff. Moreover, when the Company is asked about basic information about its residential customers, which constitute 90% of its customer base, it claims to have little knowledge. Yet, with its propensity for spending, the Company continues to build projects for forecasted load growth that has yet to materialize. I don't believe that the Company has shown that its decisions reflect appropriate, efficient, effective, and timely decision-making and as such, propose to remove post-test year plant for ratemaking purposes.

My fourth adjustment relates to the third, and that is the Company's proposed adjustment for residential test year sales for weather normalization. As noted above the Company claims it has little knowledge about its customers and this brings into question the accuracy of attributing any sales variation to weather as opposed to economic conditions. I propose to only allow half of the proposed weather normalized sales variation for residential customers to be allowed in rates.

My fifth and final adjustment relates to the UNS headquarters building. TEP's parent corporation, UNS, conceived and built this building in the downtown location. The downtown location was critical because UNS was trying to gain investment tax credits which would have garnered the parent Company considerably financial benefit. When the tax credits became unavailable and after construction of the new building was complete and the employees were about to move into the building, ownership was transferred from the non-regulated entity, UNS, to the regulated entity, TEP, which happened to be filing for a rate case shortly thereafter. Effectively, the parent is attempting to shift the cost burden and risk associated with it from its shareholders to TEPs ratepayers. When UNS was allowed to form a holding Company back in 1997 there was a safeguard provision to ensure that the formation of the Holding Company structure would not result in adverse consequences to TEP. That provision was that the parent company would charge the lower of embedded costs or the prevailing market rent for any exchange of goods between the parent company and the affiliate. Since the market rent in Tucson is considerably less than the embedded cost of the building, for ratemaking purposes, I propose to reflect this provision of the holding company order into the rate setting process. This would be effectuated by removing the building from TEP's rate base, removing the associated expenses and imputing a market based rent.

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services in electric, gas and water utility industry matters, and specializing in the fields of rates, planning and utility economics. My office address is 235 Lark Street, Albany, New York 12210.

Q. PLEASE DESCRIBE THE HUDSON RIVER ENERGY GROUP.

A. The Hudson River Energy Group ("HREG") is an engineering consulting firm specializing in the fields of rates, planning, economics and utility operations for the electric, natural gas, steam and water utility industries. HREG was founded in 1998 and has served a wide variety of clients including municipal utilities, government agencies, state commissions, consumer advocates, law firms, industrial companies, power companies, and environmental organizations. HREG conducts rate design and cost of service studies, and designs performance based rate plans. HREG also assists clients in handling the complexities of deregulation and restructuring, including Open Access Transmission Tariff pricing, unbundling of rates, resource adequacy, transmission planning policies and power supply. During HREG's existence, we have proffered our expertise before the Federal Energy Regulatory Commission ("FERC" or "Commission") and a large number of state utility regulatory commissions across the country.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now known as "Clarkson University") in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Public Service Commission ("NYPSC") in the Rates and System Planning sections of the Power Division. My responsibilities included, resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the state. These duties also encompassed rate design, performing embedded and marginal cost of service studies, as well as depreciation studies.

Before leaving NYPSC, I was responsible for directing all engineering staff during major proceedings, including those relating to rates, integrated resource planning ("IRP") and environmental impact studies. In February 1997, I left NYPSC and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own consulting firm.

In my 35 years of experience, I have testified as an expert witness in utility rate proceedings on more than one hundred occasions before various utility regulatory bodies, including: the Arizona Corporation Commission, the Connecticut Department of Public Utility Control (now the Connecticut Public Utilities Regulatory Authority), the Delaware Public Service Commission, the Illinois Commerce Commission, the Kentucky Public Service Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the Mississippi Public Service Commission, NYPSC, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, and the FERC. Currently, I advise a variety of regulatory commissions, consumer advocates, municipal utilities, and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A summary of my professional qualifications and experience, including a listing of cases in which I have proffered testimony, is attached as Exhibit__FWR-1.

Q. **ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO").

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

SCOPE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked to review the engineering justification and ratemaking need for certain revenue requirement aspects of the Tucson Electric Power Company's ("TEP" or "the Company") rate request.

Q. HAVE YOU PREPARED AND EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes, I have prepared the following:

Exhibit-FWR-1 - Resume of Frank W. Radigan

Exhibit-FWR-2 - Response to RUCO 8.06
Exhibit-FWR-3 - Response to RUCO 8.05
Exhibit-FWR-4 – Confidential Response to Staff 3.3
Exhibit-FWR-5 - Excerpt from TEP 2015 FERC Form 1
Exhibit-FWR-6 - Response to AECC 12.4
Exhibit-FWR-7 - Excerpt from TEP 2014 IRP
Exhibit-FWR-8 - Confidential Planning Memorandum for Canoa Ranch
Exhibit-FWR-9 - Confidential Planning Memorandum for Lateral
Exhibit-FWR-10 - Responses to RUCO 7.3 and 7.4
Exhibit-FWR-11 - Responses to RUCO 7.11
Exhibit-FWR-12 - Response to RUCO 8.04
Exhibit-FWR-13 - Response to RUCO 7.20
Exhibit-FWR-14 - Response to RUCO 7.13 in 2012 Rate Case
Exhibit-FWR-15 - Confidential Extract from Response to RUCO 7.13 from 2012 TEP Rate Case
Exhibit-FWR-16 - Confidential Presentation on Tax Credits

Exhibit-FWR-17 - Response to RUCO 7.2 from 2012 TEP Rate Case
Exhibit-FWR-18 - New Headquarters Brochure
Exhibit-FWR-19 - Excerpts from UNS' 10-Ks for 2009 and 2010

SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's presentation is a study in contrasts. On the one hand, Company President David Hutchens testified that the impact of EE and DG on the Company's retail electric sales has been significant (Hutchens Direct at 7). He notes that since 2012, cumulative sales reductions attributable to energy efficiency and distributed generation reached nearly 1,000,000 MWh, which equates to about 11% of TEP's test year sales (Ibid). On the other hand, the Company has acquired 413 MW of Gila River Unit #3 and in 2015, the Company's growing renewable energy portfolio (including DG) is expected to expand to over 500 megawatts ("MW") as compared to 56 MW in the Company's last rate proceeding (Hutchens Direct at 6-7). In addition, customer installed solar applications continue unabated at approximately 2 MW a month and now total approximately 180 MW (Ibid).

On the one hand the Company has been told that its load forecasts appear to be optimistic in that is assumes a rapid return to historical load growth and the ACC Staff recommended that TEP reexamine their load forecasting techniques[1]. Yet, Company President David Hutchens states that from the

[1] **DOCKET NO. E-00000V-13-0070 -** Staff'statewide review and assessments of the integrated resource plans, filed on December 19, 2014, page 114.

period of January 1, 2012 to June 30, 2015, TEP invested approximately $1.3 billion in order to continue providing its customers with safe and reliable service (Hutchens Direct at 25). On a net plant basis for retail customers these investments increase rate base from $1.5 billion in the last case[2] to $2.1 billion in this case (Schedule B) an increase of 40%. The Company does not seem to understand its building for load that under current market conditions is unlikely to return.

Company witness Dallas Dukes testifies that use per customer, since 2011, TEP has seen a decline of approximately 7.5% in just the residential customer class alone (Dukes Direct at 14). Yet, Company President Hutchens testifies that TEP expects to supply at least 30 percent of TEP's energy from renewable resources by 2030 – <u>doubling the level the Company must achieve by 2025 under Arizona's RES Hutchens Direct at page 7</u> and Sheehan Direct footnote 41 at page 32, emphasis added). The obvious question here is why is the going so far above and beyond investing in plant if it must be spread over a smaller base?

On the one hand, Company President Hutchens states that the recent Gila River acquisition is part of a strategy to reduce reliance on coal [3]but this 413

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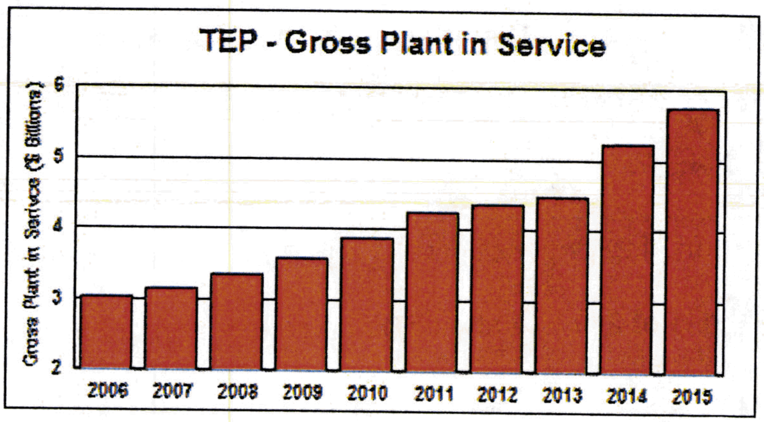
[2] Docket No. E-01933A-12-029, Settlement Agreement, Attachment A, under Column titled Settlement, Row titled rate base.

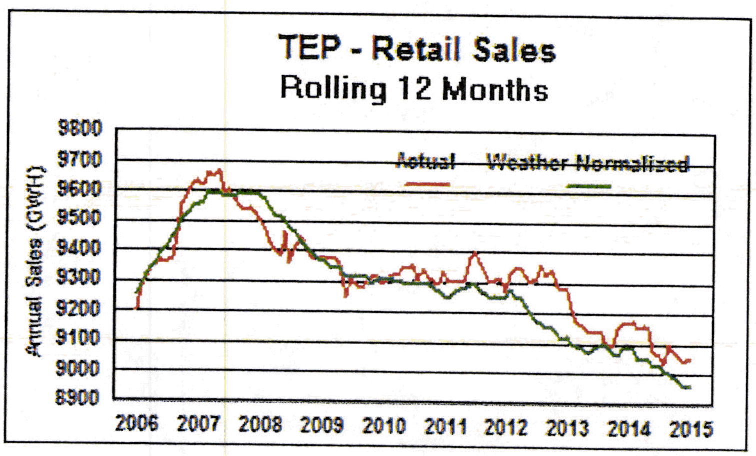
[3] Hutchens Direct at 7.

MW acquisition did not replace the 156 MW Sundt 4 since that unit simply switched from using coal to using gas as its primary fuel. Also, he testifies that Gila River was purchased in anticipation of a reduction in coal capacity as SGS[4] yet because of issues related to the co-owners of SGS 1 wanting to continue ownership in the plant, TEP is in the process of acquiring the remaining 195 MW of SGS 1. Thus, at a time of declining peak demand this 413MW acquisition is actually only replacing the scheduled retirement of 170MW of capacity of San Juan Unit 2. Finally, facts have changed since Mr. Hutchens put in his testimony at the beginning of the case, TEP will not reduce its coal capacity down from 1,551 MW at the end of 2011 to 1030 MW at the end of 2015 as he shows in his testimony but rather only down to 1,395 MW since the Company has moved to acquire the remaining portion of Springerville Unit 1 and San Juan 2 is not scheduled to retire until the end of 2017. It should be noted that none of this is without costs as the Company seeks full cost recovery for Gila River, the stranded assets at Sundt, the stranded assets at San Juan and for full cost recovery for acquisition of all of Springerville Unit 1.

[4] In December 2014 and January 2015, TEP purchased leased interests in SGS Unit 1 totaling 35.4% for an aggregate purchase price of $66 million. These purchases brought TEP's total ownership interest in the unit to 49.5%. Prior to January 1, 2015, TEP leased 100% of SGS Unit 1, received 100% of its 387 MW capacity and owned an equity interest in one of the leases covering a 14% share of the unit.

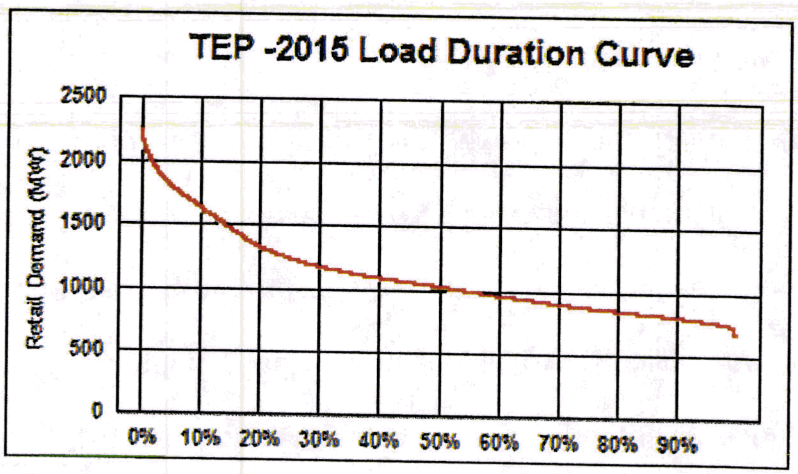
I have prepared the graphs below to illustrate my points[5]. The first graph illustrates the investment made by the Company in its system over the last ten years while the second graph represents the Company's annual sales on a rolling twelve month basis (a rolling 12 month calculation is used to determine trends with each point being one year of data with the next data point adding one month of data and subtracting the oldest month from the calculation). This information was taken supplied from in responses to RUCO 8.06 (Exhibit FWR-2)



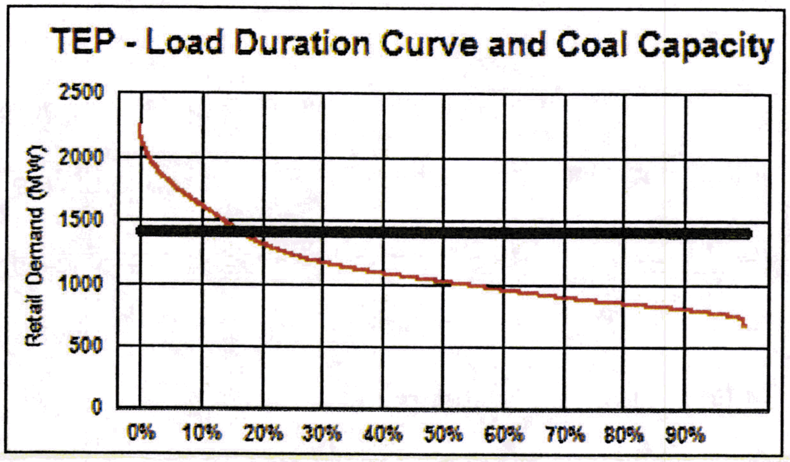


[5] TEP Gross Plant in service from TEP FERC Form 1, 2006-2015 inclusive, page 207, TEP retail sales from responses to RUCO 8.06.

As can be seen these two graphs are trending in the opposite directions. I think we should also be cognizant of two other graphs that illustrate TEP's system. The first is a load duration curve which is developed by taking the peak demand in each hour of the year and ranking it from highest to lowest. This graph was developed from data supplied in response to RUCO 8.05 (Exhibit-FWR-3). This is a curve that is used in generation planning and integrated resource planning ("IRP") and is useful when comparing capacity resource options to the load being experienced by the Company. The X axis is the % of hours in the year. As shown below TEP's load is 1,000 MW or less for 50% of all hours in the year.



The next graph is the load duration curve again but the total amount of coal capacity under the Company's operational control for the test year is also shown (Coal capacity data taken from response to Noble 3.6). This curve is useful to compare the amount of base load capacity the Company has versus the need of its retail customers. As shown on the graph below, TEP has a considerable amount of excess coal capacity for a large percentage of time. In fact, TEP coal generation resources exceed its retail load 83% of the time in 2015.



I present these graphs as contextual background to the discussion and adjustments that follow. The Company is asking for a large amount of outstanding issues to be addressed in this case and the cost of them is large. Gila River Unit 3 is being placed in rate base. The Company wants to recover the increased cost for Springerville Unit 1 in the fuel adjustment clause. The Company seeks full cost recovery of the stranded assets related to the Sundt Coal Handling facilities and the pending retirement of San Juan Unit 2. The Company seeks to shorten the service life of San Juan Unit 1 because of problems that may or may not occur almost a decade from now. If these factors were not enough there is the issue of increased rate base to recover the cost of the Company's penchant for new

investments while at the same time load continues a steady ten year old decline.

I propose a series of adjustments to the Company's presentation. The first addresses the capacity acquisition issue. When the Company has excess capacity, it sells it in the wholesale market to recover some of the costs for supporting that capacity. This is done under FERC approved wholesale power contracts. The Company's presentation removes some of the sales unjustly and I propose an adjustment which is more reflective of conditions that occurred in the test year and appear likely to reoccur in the year following when rates are reset, 2017.

My second adjustment is to depreciation. Here I propose two adjustments. The first is to reject the shortening of the service life for San Juan Unit 1. The Company has no firm basis to make this adjustment and given the rate impact, an almost $13 increase in depreciation expense, and the fact that the Company is asking ratepayers to pay for so many other things in this case, I believe the Company's proposed shortening of the service life is premature.

My third adjustment relates to the recovery of post-test year plant. Based on past precedent in this State, post-test year plant might be allowed for recovery in rates when the plant is necessary for the provision of services

and reflects appropriate, efficient, effective, and timely decision-making. As will be discussed in more detail below this Company has a history of being overly optimistic in its load projections and has been asked to review this by Commission Staff. Moreover, when the Company is asked about basic information about its residential customers, which constitute 90% of its customer base, it claims to have little knowledge. Yet, with its propensity for spending, the Company continues to build projects for forecasted load growth that has yet to materialize. I don't believe that the Company has shown that its decisions reflect appropriate, efficient, effective, and timely decision-making and as such, propose to remove post-test year plant for ratemaking purposes.

My fourth adjustment relates to the third, and that is the Company's proposed adjustment for residential test year sales for weather normalization. As noted above the Company claims it has little knowledge about its customers (making no attempt to track the number of vacant homes or the number of seasonal customers) - this brings into question the accuracy of attributing any sales variation to weather as opposed to economic conditions. I propose to only allow half of the proposed weather normalized sales variation for residential customers to be allowed in rates.

My fifth and final adjustment relates to the UNS headquarters building. TEP's parent corporation, UNS, conceived and built this building in the

downtown location. The downtown location was critical because UNS was trying to gain investment tax credits which would have garnered the parent Company considerably financial benefit. When, through the course of events, the tax credits became unavailable after construction of the new building was complete and the employees were about to move into the building, ownership was transferred from the non-regulated entity, UNS, to the regulated entity, TEP, which happened to be filing for a rate case shortly thereafter. Effectively, the parent is attempting to shift the cost burden and risk associated with it from its shareholders to TEPs ratepayers. When UNS was allowed to form a holding Company back in 1997 there was a provision in the Commission's decision approving the holding company as a safeguard to ensure that the formation of the Holding Company structure would not result in adverse consequences to TEP. That provision was that the parent company would charge the lower of embedded costs or the prevailing market rent for any exchange of goods between the parent company and the affiliate. Since the market rent in Tucson is considerably less than the embedded cost of the building, for ratemaking purposes, I propose to reflect this provision of the holding company order into the rate setting process. This would be effectuated by removing the building from TEP's rate base, removing the associated expenses and imputing a market based rent.

JURISDICTIONAL ALLOCATION

Q. COULD YOU PLEASE DISCUSS THE ISSUE OF JURISDICTIONAL ALLOCATIONS?

A. Yes, some aspects of the Company's operations must be removed from the ratemaking process as they are not under the Commission's jurisdictional control for rate setting. The clearest example of this is the issue of transmission where the Company's transmission assets are not under Commission control but rather have been transferred and TEP purchases transmission under an open access transmission tariff. Thus, all transmission assets and expenses are removed from TEP's income statement and rate base for ratemaking purposes. A similar issue comes up with generation which is sometimes sold in the wholesale market. For sales that are short term in nature, less than a year, the revenues and fuel costs are credited to the fuel adjustment mechanism. Long term wholesale sales, contracts over a year in length, are sold at rates approved by the Federal Energy Regulatory Commission. In the Company's presentation it adjusts the income statement and rate base calculations so that the plant associated with these transactions are not recovered within jurisdictional base rates (Dukes direct at 51).

Q. HAVE YOU REVIEWED THE COMPANY'S CALCULATION RELATING TO THIS ADJUSTMENT?

A. Yes and I believe it needs some refinement. Staff asked a discovery question seeking the work papers and supporting documents used to derive the jurisdictional allocations used for each pro-forma adjustment. This was supplied in a confidential spreadsheet, STF3.3JurisdictionalAllocation-Confidential.xlsx. The tab used to allocate the demand related aspects of this issue is attached as Exhibit FWR-4 and shows both retail and wholesale demands for 2015. For wholesale demands, the information is also broken out by contract. To develop their pro-forma adjustment the Company removed 200 MW out of the 296 MW of FERC jurisdictional contracts in order to develop its jurisdictional allocator (See column (h)). No explanation in the discovery response, the spreadsheet provided or the direct testimony of the Company addresses this removal.

Q. DO YOU BELIEVE THE REMOVAL OF THESE TWO CONTRCTS IS REASONABLE?

A. No. One contract for 100 MW is titled Shell. On TEP's FERC Form 1 this contract is listed as being with Shell Energy North America (US) LLP (see Exhibit FWR-5). In response to a discovery question in this case TEP states that this contract was put into place after the acquisition of Gila River Unit 3 and the contract expires on December 31, 2017 (See Exhibit FWR-6). As new rates are scheduled to go into effect on January 1, 2017 it is

unreasonable to take this contract out. The second contract that was removed before calculating the jurisdictional allocator was titled SRP which on TEP's FERC Form 1 this contract is listed as being with the Salt River Project Agricultural Improvement and Power District. A review of TEP's 2014 IRP shows that the SRP project was part of its long term wholesale power supply obligations but that the contract terminated sometime in 2016 (See Exhibit FWR-7). While this would indicate this could be the basis for a proper pro-forma adjustment, a review of TEP's 2016 IRP shows that the Company has entered into a new wholesale power supply contract with the Navopache Electric Cooperative for 44 MW of capacity beginning in 2017. I would also note that the existing contract with the TRICO electric cooperative, which was entered into place after the acquisition of Gila River Unit 3, is scheduled to increase from 50 MW to 85 MW in 2018.

Q. GIVEN THIS INFORMATION WHAT DO YOU RECOMMEND FOR RATE SETTING PURPOSES?

A. Given that the Company has provided no explanation as to why it removed these two contracts, the fact that one of them will continue for at least a year after when new rates are set, that at least one new wholesale contract has been entered into after the end of the test year, that the Company has a history of marketing capacity acquisitions in the wholesale market when they are needed for retail customers, and the fact that retail load has exhibited decline and therefore makes more capacity available for the

wholesale market, I believe that the Company has not shown its adjustment to be reasonable and should therefore be rejected.

I should also note that TEP is requesting that the operational costs of a portion of Springerville Unit 1 be recovered through the PPFAC (Grant Direct at 24). It is important for retail customers that the proper jurisdictional allocation of costs should also apply to the Company's requested recovery of any costs associated with generation through the PPFAC.

DEPRECIATION

Q. PLEASE DISCUSS YOUR ADJUSTMENTS TO DEPRECIATION EXPENSE?

A. As I noted in the introduction to my testimony, I propose two adjustments. The first relates to the service life of San Juan Unit 1 which the Company is proposing a change to the retirement date from 2036 to 2027 based on the feasibility of future coal supply agreement extensions (Sheehan Direct at 26:1-22). As Mr. Sheehan explains the current coal supply contract is scheduled to end by 2022 and any extension to the contract must be renegotiated by 2019 (Ibid). Without given many specifics Mr. Sheehan states there are numerous factors impacting the future of the coal supply and he recommends that the Commission only expect a five year contract extension of the existing agreement.

Q. PLEASE COMMENT.

A. Mr. Sheehan provides little in the way of facts to his proposal. As he notes numerous factors could act to shorten the life of the existing mine and there are numerous other factors that could act to lengthen the life. One most notable is that San Juan Unit 2 was scheduled to cease operations in 2033 (Sheehan Direct at 23) and is now being retired at the end of 2017. All else being equal then some coal mine capacity that was expected to be used for supplying San Juan Unit 2 could now be used to supply San Juan Unit 1. Thus, by using existing resources the mine could supply San Juan 1 for a number of years beyond 2027. Given the facts that nothing is known for certain, I recommend that the current service be maintained.

Q. COULD YOU PLEASE DISCUSS YOUR SECOND ADJUSTMENT TO DEPRECIATION?

A. Yes. The Company is in the process of acquiring all interest in Springerville Unit 1 which will change it from a minor lease owner to actual owner of the unit. As the Company already owns Unit 2, this 793 MW of capacity is a large portion of the Company's generation portfolio. In addition, as these are newer units, they do not suffer some of the same environmental issues impacting the other coal stations in the Company's fleet. Finally, since the Company is acquiring more of this station it appears that this will be the Company's flagship coal generating station on a going forward basis. The service lives of this station, however, do not reflect this outlook. The

expected retirement date Unit 1 is 2045 and the service life for Unit 2 is expected to be 2050. The leasehold improvements at Unit 2 are set to last only until 2024. Given that this is TEP's best unit and it will soon own all of Units 1 and 2, depreciation rates should reflect the Company's long term outlook for the plant and I propose an expected retirement date for Units 1, Unit 2 and all common equipment at 2050.

Q. COULD YOU PLEASE ADDRESS THE ISSUE OF EXCESS DEPRECIATION RESERVE?

A. Yes, there was a provision from the Settlement in the last TEP rate case that any excess depreciation reserve in production plant be used to write off stranded assets due to early retirements and any remaining excess be returned to ratepayers over 15 years[6]. In this case the Company used the excess reserve to write of the Sundt coal handling facilities and the remaining assets of San Juan 2. The Company did this calculation based on 2014 plant balances. However, since rates are going to be reset on January 1, 2017, the Company's calculations does not recognize that both assets continue to accrue depreciation expense which is credited to the depreciation reserve. All else being equal therefore, the Company's presentation removes too much excess deprecation reserve than is necessary to write off these assets. I calculate the amount in question to be approximately $20 million. While the coal handling facilities at Sundt are

[6] Docket No. E-01933A-12-029, Settlement Agreement, Section 20.3.

no longer used a calculation could be done but for San Juan 2, because the plat will be operating for a full three years after the Company performed its calculation there will still be additions and retirement at the plant, the correct calculation will not be able to be done until after 2017. Said another way, it is only after the San Juan 2 Unit is fully retired will the true effect that the write off will have on the excess depreciation reserve. As such, if any excess depreciation reserve is available after all depreciation rates are set in this case, I would recommend that it be revisited in the next rate proceeding and not passed back to ratepayers over the 15 years as contemplated in the Settlement from the last rate case.

POST TEST YEAR PLANT ADDITIONS

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S REQUEST FOR POST TEST YEAR PLANT ADDITIONS?

A. Yes. TEP has adjusted its rate base to include approximately $51.8 million of plant additions that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2015 (Dukes Direct at 43). The Company has also adjusted its rate base to include approximately $20.8 million of plant additions for renewables that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2016 (Dukes Direct at 44). This adjustment extends out an additional 12 months beyond the non-renewable post-test-year cut-off (Ibid). This allows for the reflection of these renewable asset investments approved through the REST

application process to be recovered through base rates as opposed to being recovered through the REST tracker (Ibid).

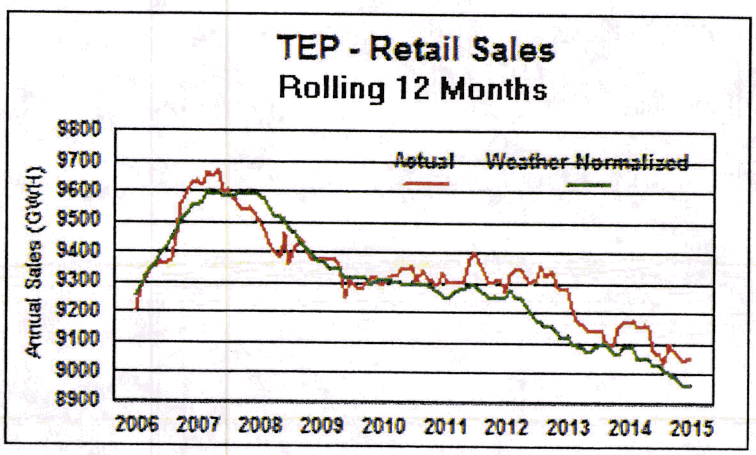
Mr. Dukes argues that these projects will be benefiting customers by the time new rates are effective (Dukes Direct at 43 and again at 44). Mr. Dukes goes on to state that by allowing rate recovery in this rate case will more closely align cost recovery to the Company with the benefits that are currently being provided to existing customers (Dukes Direct at 43). Mr. Dukes also states that rate recovery in this rate case also lowers the cost to customers by limiting the amount of Allowance For Funds Used During Construction ("AFUDC") charged to the assets, thereby reducing the future depreciation and carrying costs associated with this plant (Ibid). Mr. Dukes states that the Company's request is consistent with the Commission's past orders with respect to post test year plant additions as well as the rate treatment allowed it in the last rate case (Dukes Direct at 43 and at 44). Finally, Mr. Dukes concludes that the timely recovery of costs incurred to maintain a safe, reliable electric system is necessary to mitigate larger rate impacts that result from the use of historic test years combined with little to no increase in sales (Dukes Direct at 43).

Q. **COULD YOU PLEASE COMMENT ON THE COMPANY'S REQUEST?**

A. Yes. I would like to start with Mr. Duke's final argument. I think what he means is that it is cheaper to give them the money now while sales are

relatively high because if they have to wait until the next rate case sales will be lower so the resultant percentage increase in rates necessary to reflect them in rate base will be higher. Of course that is really the issue here because one of the caveats that the Commission has used in allowing post test year plant additions is that the utility must show the plant is necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making.

When the utility's sales and peak demand are declining due to the effect of energy efficiency, the growth of distributed generation and persistent weak economic conditions, one must question why the utility continues to plan for and add additional plant. Again, we should keep in mind the trend line for the Company's retail sales.



In this current retail sales environment, if increased safety and reliability is the goal as Mr. Dukes states then one may not need to put in new

investments while at the same time load continues a steady ten year old decline.

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Q. PLEASE COMMENT.

A. Mr. Sheehan provides little in the way of facts to his proposal. As he notes numerous factors could act to shorten the life of the existing mine and there are numerous other factors that could act to lengthen the life. One most notable is that San Juan Unit 2 was scheduled to cease operations in 2033 (Sheehan Direct at 23) and is now being retired at the end of 2017. All else being equal then some coal mine capacity that was expected to be used for supplying San Juan Unit 2 could now be used to supply San Juan Unit 1. Thus, by using existing resources the mine could supply San Juan 1 for a number of years beyond 2027. Given the facts that nothing is known for certain, I recommend that the current service be maintained.

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A. Yes. The Company is in the process of acquiring all interest in Springerville Unit 1 which will change it from a minor lease owner to actual owner of the unit. As the Company already owns Unit 2, this 793 MW of capacity is a large portion of the Company's generation portfolio. In addition, as these are newer units, they do not suffer some of the same environmental issues impacting the other coal stations in the Company's fleet. Finally, since the Company is acquiring more of this station it appears that this will be the Company's flagship coal generating station on a going forward basis. The service lives of this station, however, do not reflect this outlook. The

expected retirement date Unit 1 is 2045 and the service life for Unit 2 is expected to be 2050. The leasehold improvements at Unit 2 are set to last only until 2024. Given that this is TEP's best unit and it will soon own all of Units 1 and 2, depreciation rates should reflect the Company's long term outlook for the plant and I propose an expected retirement date for Units 1, Unit 2 and all common equipment at 2050.

Q. COULD YOU PLEASE ADDRESS THE ISSUE OF EXCESS DEPRECIATION RESERVE?

A. Yes, there was a provision from the Settlement in the last TEP rate case that any excess depreciation reserve in production plant be used to write off stranded assets due to early retirements and any remaining excess be returned to ratepayers over 15 years[6]. In this case the Company used the excess reserve to write of the Sundt coal handling facilities and the remaining assets of San Juan 2. The Company did this calculation based on 2014 plant balances. However, since rates are going to be reset on January 1, 2017, the Company's calculations does not recognize that both assets continue to accrue depreciation expense which is credited to the depreciation reserve. All else being equal therefore, the Company's presentation removes too much excess deprecation reserve than is necessary to write off these assets. I calculate the amount in question to be approximately $20 million. While the coal handling facilities at Sundt are

[6] Docket No. E-01933A-12-029, Settlement Agreement, Section 20.3.

no longer used a calculation could be done but for San Juan 2, because the plat will be operating for a full three years after the Company performed its calculation there will still be additions and retirement at the plant, the correct calculation will not be able to be done until after 2017. Said another way, it is only after the San Juan 2 Unit is fully retired will the true effect that the write off will have on the excess depreciation reserve. As such, if any excess depreciation reserve is available after all depreciation rates are set in this case, I would recommend that it be revisited in the next rate proceeding and not passed back to ratepayers over the 15 years as contemplated in the Settlement from the last rate case.

POST TEST YEAR PLANT ADDITIONS

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S REQUEST FOR POST TEST YEAR PLANT ADDITIONS?

A. Yes. TEP has adjusted its rate base to include approximately $51.8 million of plant additions that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2015 (Dukes Direct at 43). The Company has also adjusted its rate base to include approximately $20.8 million of plant additions for renewables that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2016 (Dukes Direct at 44). This adjustment extends out an additional 12 months beyond the non-renewable post-test-year cut-off (Ibid). This allows for the reflection of these renewable asset investments approved through the REST

application process to be recovered through base rates as opposed to being recovered through the REST tracker (Ibid).

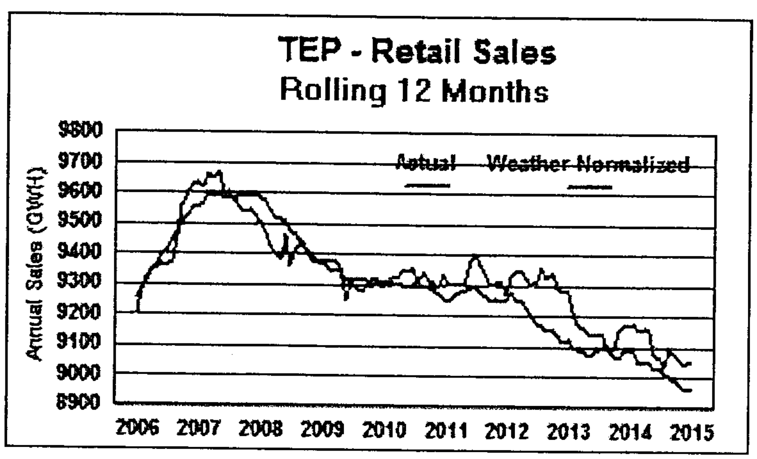
Mr. Dukes argues that these projects will be benefiting customers by the time new rates are effective (Dukes Direct at 43 and again at 44). Mr. Dukes goes on to state that by allowing rate recovery in this rate case will more closely align cost recovery to the Company with the benefits that are currently being provided to existing customers (Dukes Direct at 43). Mr. Dukes also states that rate recovery in this rate case also lowers the cost to customers by limiting the amount of Allowance For Funds Used During Construction ("AFUDC") charged to the assets, thereby reducing the future depreciation and carrying costs associated with this plant (Ibid). Mr. Dukes states that the Company's request is consistent with the Commission's past orders with respect to post test year plant additions as well as the rate treatment allowed it in the last rate case (Dukes Direct at 43 and at 44). Finally, Mr. Dukes concludes that the timely recovery of costs incurred to maintain a safe, reliable electric system is necessary to mitigate larger rate impacts that result from the use of historic test years combined with little to no increase in sales (Dukes Direct at 43).

Q. **COULD YOU PLEASE COMMENT ON THE COMPANY'S REQUEST?**

A. Yes. I would like to start with Mr. Duke's final argument. I think what he means is that it is cheaper to give them the money now while sales are

relatively high because if they have to wait until the next rate case sales will be lower so the resultant percentage increase in rates necessary to reflect them in rate base will be higher. Of course that is really the issue here because one of the caveats that the Commission has used in allowing post test year plant additions is that the utility must show the plant is necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making.

When the utility's sales and peak demand are declining due to the effect of energy efficiency, the growth of distributed generation and persistent weak economic conditions, one must question why the utility continues to plan for and add additional plant. Again, we should keep in mind the trend line for the Company's retail sales.



In this current retail sales environment, if increased safety and reliability is the goal as Mr. Dukes states then one may not need to put in new

equipment. Rather just wait as the existing equipment becomes unloaded due to the declining sales which thereby cause increased reliability. As I mentioned in my introduction this Company was asked by the Staff of the Commission to reexamine its load forecasting process because it appeared to be somewhat optimistic. This advice hasn't taken root as the Company's core level of investment in transmission and distribution is on par with historic levels (See Exhibit to Grant Direct, KCG-1) and the Company's 2016 IRP load forecasting section heavily relied on the anticipated addition of the Rosemont copper mine, whose owners announced indefinite delay in the project the day the IRP was filed[7].

The consequences of building too much plant is telling. In TEP's last rate case, when asked to review their capital spending, I raised questions about the wisdom of their building program. One of these projects I addressed was the new Canoa Ranch Substation. **[BEGIN CONFIDENTIAL]** [redacted]

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[7] http://www.tucsonweekly.com/TheRange/archives/2016/03/01/rosemont-mine-put-on-hold-by-hudbay-minerals

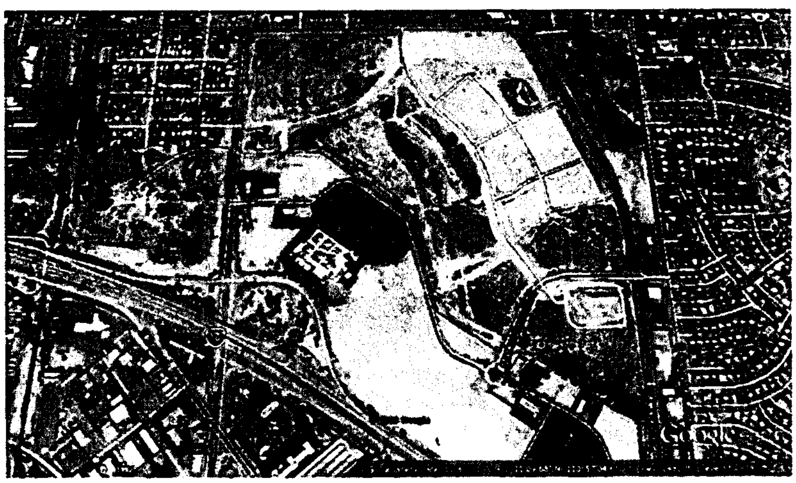
[redacted]

[redacted]

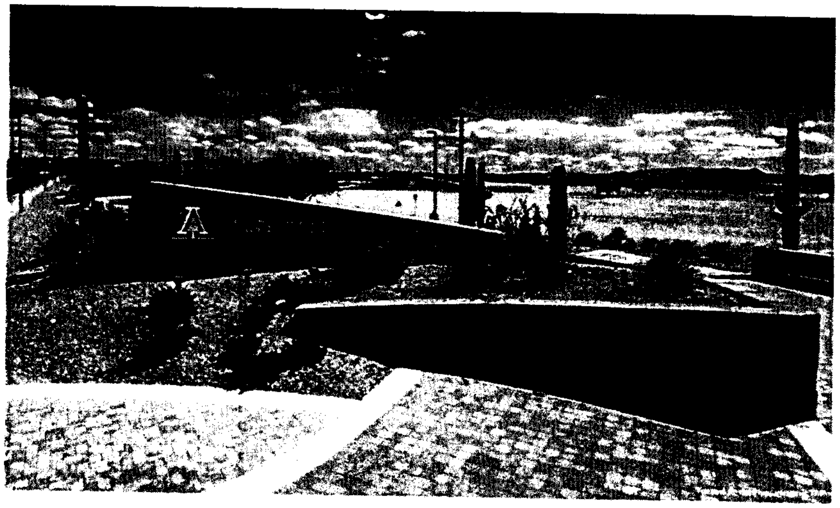
[redacted]

[END CONFIDENTIAL]

Based on my review of upcoming projects in the transmission and distribution system, I am fearful that this build out of the system in hopeful anticipation for historic load growth is continuing. One case in point is the planned Kino Substation. The Kino area in southern Tucson is serviced by five substations, 21st St, 35th St, Pueblo Gardens, Drexel, and Fair St. Recent and TEP forecasts that load growth and a large planned community called "The Bridges" has created an increase in load for this area that will continue as The Bridges gets built out. The Bridges is a 350-acre master-planned mixed-use development consisting of 1,000,000 square feet of commercial/retail/office land uses a 350 room hotel, up to 1,084 residential units consisting of single family attached homes and a research park associated with the University of Arizona. The plan for the Bridges was originally proposed in 2007[8]. The pictures below show and aerial view and a street view of the Bridges as it exists today. As one can easily, see there has been little meaningful development at the Bridges in the last 10 years



[8] https://www.tucsonaz.gov/files/pdsd/plans/Bridges_PAD_Complete.pdf



Q. PLEASE DISCUSS WHEN IT IS APPROPRIATE TO INCLUDE POST TEST YEAR PLANT IN RATES.

A. I believe the best description of the Commission's guiding principles is that used in Decision No. 71410. There the Commission explained that its rules require the end of the test year, which is the one-year historical period used in determining ratebase, operating income and rate of return, to be the most recent practical date available prior to the filing (Ibid at page 19). The Commission noted that a utility has the freedom to choose a test year that includes all major rate base and operating income items needed to support its rate application, and to include pro forma adjustments to its chosen test year (Ibid at page 20). The Commission further noted that matching is a fundamental principle of accounting and ratemaking, and the absence of matching distorts the meaning of, and reduces the usefulness of, operating income and rate of return for measuring the fairness and reasonableness of rates (Ibid).

In that case, the Commission adopted several Staff adjustments in the case to remove proposed post-test year plant additions from the rate setting process. In its direct testimony in the case, Staff explained that the matching principle is the reason that the Commission has allowed inclusion of post-test year plant in rate base only in special and unusual situations, which could be summarized as follow:

1) when the magnitude of the investment relative to the utility's total investment is such that not including the post-test year plant in the cost of service would jeopardize the utility's financial health;
2) where the cost of the post-test year plant is significant and substantial;
3) where the net impact on revenue and expenses for the post test year plant is known and insignificant (or is revenue-neutral); and
4) where the post-test year plant is prudent and necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making (Ibid).

I believe it is this last test where TEP fails in its presentation. At a time when sales and peak are declining, a request for post test year plant recovery in rates requires a detailed presentation that the large and continuous build out of infrastructure reflects appropriate, efficient, effective, and timely decision-making. Absent such a showing on the Company's part, I recommend that no post test year plant additions be reflected in rates.

WEATHER NORMALIZATION

Q. PLEASE DISCUSS THE ISSUE OF WEATHER NORMALIZATION.

A. As explained by Company witness Craig Jones, weather normalization is a standard adjustment commonly performed in rate cases (Jones Direct at 66). It is performed to provide a best estimate of test year sales, revenues, and costs as they would have been under normal weather conditions (Ibid). Energy consumption for some of TEP's customer classes are weather sensitive (Ibid). For instance, a significant portion of energy usage in the summer comes from air conditioning load (Ibid). Some summers, however, are warmer than normal and result in the Company selling more power and receiving more revenues than in a "normal" year (Ibid). The reverse of this occurs when cooler than normal summer weather is experienced (Ibid). The purpose of weather normalization is to "average" out these differences, so one can get a better sense as to what the Company is likely to receive in revenues during a year with normal weather (Ibid). Mr. Jones then goes on to describe the Company's new method for isolating the effects of weather and he believes that the Company's new method is superior in its accuracy. (Jones Direct at 68-70).

Q. HAVE YOU REVIEWED THE COMPANY'S NEW METHOD AND UNDERLYING ASSUMPTIONS?

A. Yes to the extent I could. The Company uses ten year average of weather in its model whereas some other utilities use 20 or 30 year averages in order to adequately smooth out year to year variations in weather. The Company refused to run their model on any other term other than ten years (see responses to RUCO 7.3 and 7.4 attached as Exhibit__FWR-10) so it is impossible to test the robustness or true accuracy of the model. More troubling is the fact that the Company does not track the number of vacant homes in its service territory or the number of seasonal customers (See response to RUCO 7.11 attached as Exhibit__FWR-11). Both of these are vital in determining normal energy use. Moreover, while the Company states that use per customer has been steadily declining, (See Dukes direct at 14), when asked to break out the causes for this decline the Company was able to accurately break out the effects of weather and energy efficiency but for any other variation not predicted by its model it labeled the variation "Other Change" (See response to RUCO 8.04 attached as Exhibit__FWR-12). This category "Other Change" could be because of modeling error, estimation error in the case of the impact of energy efficiency or economic conditions such as an increase/decrease in the number of homes that are vacant or an increase/decrease in the amount of seasonal customers. The fact that this category moves up or down seemingly in a random pattern but at a magnitude that can be as large as the weather variation indicate that the Company might be well served to revisit its usage modeling and include such basic parameters as short term economic conditions (i.e. variations in the number of seasonal customers or changes in the number of vacant homes). As it is, I cannot verify that the

Company's adjustment for weather accurately measures the change due to weather or for some "Other Change". As such, I recommend that only ½ of the Company's proposed adjustment for weather for residential customers be allowed to be reflected in rates and these results in a decrease in the revenue requirement of $835,322.

NEW HEADQUARTERS BUILDING

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENT IN A NEW HEADQUARTERS BUILDING.

A. In the current rate case, TEP continues to reflect the cost of the UNS headquarters building in its rate base. At June 30, 2015, the total capitalized portion of the building was $82,583,748 of which $5,620,447 was computer and office equipment. See response to RUCO 7.20 attached as Exhibit-FWR-13).

Q. WAS THE COST AND USE OF THE NEW HEADQUARTERS BUILDING AN ISSUE IN THE COMPANY'S LAST CASE?

A. Yes. Staff Witness Ralph Smith testified that the cost of the new building was a 77% increase in TEP's corporate facility cost per employee (Docket No. E-01933A-12-0291, Smith Direct at 24:20-23). Mr. Smith then elaborated on Staff's concerns (Ibid at 25).

> Beyond the sheer magnitude of the per employee facilities cost increase, Staff's other concerns about the cost of the new building is that the new building includes substantial amounts of office space that are not currently being used, that the new building includes approximately $2.1 million cost for retail space that is not currently being used, that the building includes a cost of approximately $16 million for underground garage/parking,[6] and that TEP has not adequately substantiated that its proposed charging of new building costs to ratepayers is fair and reasonable.

To address these concerns Staff proposed removing approximately 10% of the building's cost from rate base.

Q. PLEASE PROVIDE SOME BACKGROUND ON WHY A NEW HEADQUARTERS BUILDING WAS PLANNED?

A. The Company began considering consolidating office space in mid-2007 (Exhibit__FWR-14). **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

Q. DID UNS EXAMINE MANY OPTIONS IN DECIDING WHERE TO LOCATE ITS NEW HEADQUARTERS BUILDING?

A. Yes, UNS examined 23 different locations with varying land and building sizes and different cost assumptions, such as on-site parking. No fewer than eight potential sites were rejected because the site did not make a good location for a Corporate Office complex. Five other sites were unfavorably rated as they were located outside of the downtown area. Based on a review of all material provided, it is clear that UNS was focused on a downtown site for its new corporate headquarters.

Q. ARE YOU AWARE OF ANY OTHER FACTORS THAT IMPACTED THE CONSTRUCTION OF THE NEW HEADQUARTERS BUILDING?

A. Yes, one of the major factors influencing the ownership and location of the new headquarters building was the potential availability of New Market Tax Credits. New Market Tax Credits are a Federal program to incent investment in low-income communities. The New Market Tax Credit Program was established in 2000. The credit program is incorporated in Section 45D of Internal Revenue Code. The program allows for the receipt of credit against Federal Income taxes for making Qualified Equity

Investments (QEI) in qualified community development entities (CDE's). The program was established with the expectation of creating jobs and making material improvement in the lives of residents of low-income communities or populations.

A qualified equity investment is defined as an investment into a Community Development Entity (CDE). The CDE enters into an allocation agreement with the Community Development Financial Institutions Fund (CDFI) who provides allocations of New Market tax credits to CDI's allowing them to attract investments from the private sector to be reinvested in low income communities

The program provides for credits equal to 39% of the investment into the CDI. The credit is provided over a seven years and is equal to 5% of the qualified investment in Years One-Three and 6% of the qualified investment in Years Four-Seven. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

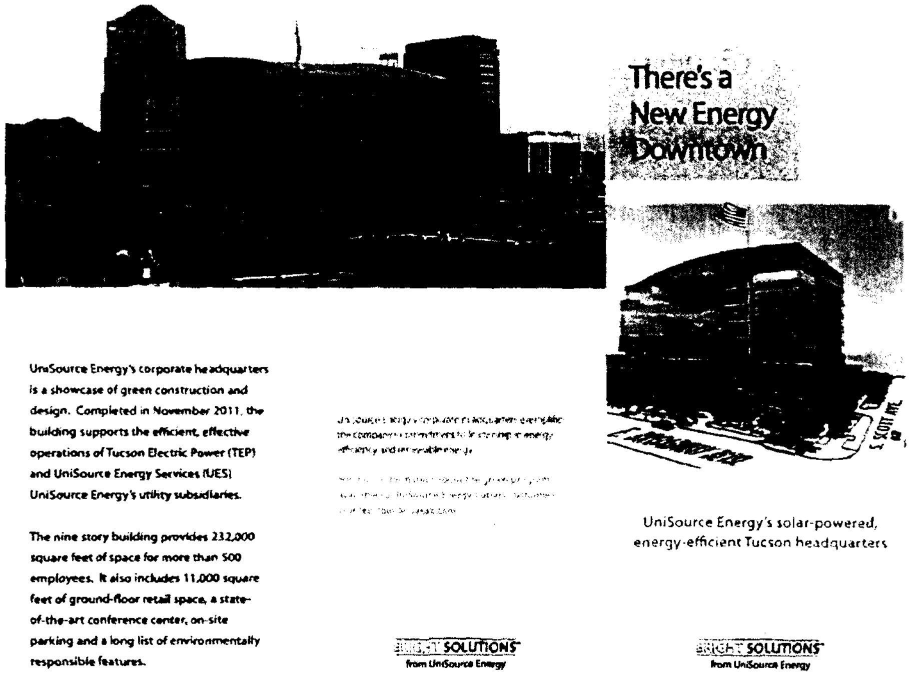
[END CONFIDENTIAL]

Q. WHEN DID UNS TRANSFER OWNERSHIP OF THE NEW HEADQUARTERS BUILDING TO TEP?

A. November 1, 2011, after construction of the new building was complete and the employees were about to move in (Exhibit__FWR-17).

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPANY'S DECISION MAKING PROCESS?

A. The facts are clear the new headquarters building was conceived as a corporate headquarters for UNS and not for TEP. The original plan and design of the building was just to bring employees with corporate duties together under one roof. That the new building is the headquarters of the UNS Corporation is still the building's main function. Brochures in the lobby of the new building describe the building as "UniSource Energy's solar-powered energy-efficient Tucson headquarters" and declare the corporate headquarters "a showcase of green construction and design" (Exhibit__FWR-18 UNS Headquarters Brochure).



While UNS may want a downtown address to improve its image and show community leadership that is certainly not a key necessity of a regulated Company such as TEP. Only long after the initial project review did the Company even consider bringing in more employees from the Irvington Road campus. It should be noted that the Irvington Road campus is not empty, the Company has no plans to sell it, and there are still hundreds and hundreds of employees at the Irvington Road facility which the Company describes as an "industrial site". The evidence is clear that the new headquarters building was conceived and designed for UNS first and TEP as an afterthought.

It is also evident that UNS vigorously pursued the project in the hope of receiving a large return on its investment through the use of new market tax credits. UNS bought the land and paid for the construction of the new facility (Exhibit__FWR-19 Excerpts from UNS 10-Ks for 2009 and 2010) in the hope of getting these tax credits. It was only after UNS became aware that it would not get the tax credits was ownership transferred to TEP.

Q. WHAT ARE THE RATEMAKING IMPLICATIONS OF THE NEW HEADQUARTERS BUILDING BEING PRINCIPALLY BUILT FOR CORPORATE PURPOSES?

A. First – if the building is owned by the parent company and rented to the regulated utility-TEP, ratepayers would be responsible for the rent expense which for ratemaking purposes is treated as an operating expense. Whereas, by transferring ownership to the utility, the capital costs associated with the building become a part of TEPs ratebase and the Company's shareholders will earn a return on and a return of those capital costs. Moreover, the losses associated with the Company's inability to rent space become the burden of the ratepayer and not Unisource's shareholder who the building was designed for in the first place. The way the Company is proposing the ratemaking treatment is far more costly to TEP's ratepayers than the rental proposition for a building that was arguably designed and acquired for UniSource's needs – not TEPs.

Second - Docket No. U-1933-97-176[9] was the proceeding whereby Tucson Electric Power Company was allowed to form a Holding Company. In that proceeding, the Company proposed 17 conditions as safeguards to ensure that the formation of the Holding Company structure would not result in adverse consequences to TEP. In approving the petition, the Arizona Corporation Commission imposed several more safeguard conditions and approved those proposed by the Company. One of the original safeguard conditions was as follows:

> The Holding Company, TEP and sister companies will strive to charge the lower of fully allocated cost or market price whenever goods, products or service are sold/provided by the Holding Company or sister companies to TEP and the higher of fully allocated cost or market whenever TEP sells/provides non-tariffed goods, products or services to the Holding Company or sister companies. The Holding Company, TEP and sister companies recognize that determining a market price for all goods, products and services being transferred in and among the Holding Company, TEP and sister companies could be a complex or difficult task for some items. Nonetheless, the Holding Company, TEP and sister companies agree to attempt to determine a market price for any good, product or service being provided by TEP to the Holding Company or sister companies as well as for any good, product or service provided by Holding Company or sister companies to TEP whenever the annual, fully allocated cost for given good, product or service being transferred exceeds $500,000 annually. Furthermore, TEP will retain such market research information (regardless of whether it is ever utilized) until such time as the Utilities Division Staff or its representative have reviewed such information.

The implications of these safeguard conditions are clear: had UNS continued to own the new headquarters building it would not be allowed to

[9] Docket No. U-1993-97-176, In the matter of the Notice of Intent of Tucson Electric Power Company to Organize a Public Company Holding Company and for Related Approvals or Waivers Pursuant to R14-2-1801, ET SEQ., Decision No. 60480 issued November 25, 1997.

charge any more than market rates for rent. If TEP owned the building, however, it would be allowed to charge the higher of embedded cost or market rates. In other words, if the cost of the new building exceeded the market rate, TEP should own the building; if the cost of the new building was less than the market rate, the holding Company became indifferent to who owns the building.

Q. WHAT DO YOU RECOMMEND BE DONE IN THIS PROCEEDING?

A. Given that the new headquarters building was built primarily for purposes of the Holding Company and for ratemaking purposes, it should be assumed to be owned by the Holding Company and TEP should pay no more than the going market rate. As such, all assets related to the land and new headquarters building should be removed from rate base, along with any operation and maintenance expenses or taxes associated with the new headquarters building. Based on the 263,365 square feet of rentable office space in the new building, the difference in cost between UNS' fully allocated cost to serve and the market rate of $20 per square foot equates to a rental rate of approximately $5.3 million per year. Removing the new headquarters from rate base and its associated expenses from the income state results in a reduction in revenue requirement of approximately $7.5 million.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

EXHIBIT FWR-1

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Rate Setting – Dover Plains Water Company – Case 14-W-0378 -- Prepared rate filing before the New York Public Service Commission for the Dover Plains Water Company to increase its annual water revenues. 2014

Rate Setting – Village of Castile – Case No. 14-E-0358 – Prepared rate filing before the New York Public Service Commission for the Village of Castile Electric Department to increase its annual electric revenues. 2014

Depreciation Study – Village of Swanton – On behalf of the Village of Swanton, Vt. Electric Department prepared a depreciation study for use in setting new depreciation rates to be submitted to the Vermont Public Service Board. 2014

Rate Setting – Village of Hamilton – Case 13-G-0584 – On behalf of the Village of Hamilton, NY designed initial rates for new municipal gas utility. 2013

Rate Setting – Fillmore Gas Company - Case No. 13-G-0039 - Prepared rate filing before the New York Public Service Commission for the Fillmore Gas Company to increase its annual gas revenues. 2013

Rate Setting – Alliance Energy - Case No. 12-G-0256 - Prepared rate filing before the New York Public Service Commission for the Alliance Energy Transmission, LLC to increase its annual gas transportation. 2012

Rate Study – Atmos Energy – Docket No. 11-UN-184 – On behalf of the Mississippi Public Service Commission, submitted report on reasonableness of Company's depreciation study. 2012

Rate Study – Entergy Mississippi –Docket No. 11-UA-83 -- On behalf of the Mississippi Public Service Commission, prepared report on the reasonableness of Entergy Mississippi's depreciation study. 2012

Rate Case Cost of Service Study – Mississippi Power Company – On behalf of the Mississippi Public Service Commission, prepared report on reasonableness of embedded cost of service study submitted by Mississippi Power Co. 2012

Rate Case Cost of Service Study – Boonville, NY – Prepared class load study and embedded cost of service study to justify change in rate design for the purpose of conserving energy. 2010-2012

Rate Setting – Alliance Energy Transmission - Case No. 12-G-0256 – Prepared rate filing before the New York Public Service Commission for Alliance Energy Transmission. 2012

Rate Setting – Hamilton, NY - Case No. 12-E-0286 - Prepared rate filing before the New York Public Service Commission for the Village of Hamilton, NY to increase its annual electric revenues. 2012

Rate Setting – Fairport, NY – Case No. 11-E-0357 - Prepared rate filing before the New York Public Service Commission for the Village of Fairport, NY to increase its annual electric revenues. 2011

Jurisdictional Cost of Service – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

Rate Analysis – Southwestern Power Company – On behalf of a coalition of retail customers analyzed reasonableness of utility's request to include the costs of Construction Work In Progress Expenditures in rates for a power plant known as the Turk Plant. 2010

Rate Study – Stowe Electric Department, VT – Docket No. 8169 – For small municipal electric utility, filed rate case before the Vermont Public Service Board. 2010

Docket No. 10-10-03 – Assisted in the CT OCC's review and development of recommendations for the Review of the 2011 Conservation and Load Management Plan. 2010

Rate Setting – Endicott, NY - Case No. 10-E-0588 – Prepared rate filing before the New York Public Service Commission for the Village of Endicott, NY to increase its annual electric revenues. 2010

Rate Case Cost of Service Study – Heritage Hills Water Works – For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Setting Training – MMWEC – Assisted in training MMWEC staff on rate setting process so that they could provide service to members. 2009

Rate Setting – Connecticut Natural Gas -- Docket No. 08-12-06 - Assisted the Connecticut Office of Consumer Counsel on the analysis of the reasonableness of the of the Company's proposed revenue requirement. 2009

Rate Filing – Heritage Hills Water Works – Case No. 08-W-1201 – Prepared rate filing before the New York PSC for the Heritage Hills Water Works Corporation to increase its annual water revenues. 2008

Rate Study – Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation. 2008

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reductions control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 9344 – Green Ridge Utilities – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2014

FC 1115 – Washington Gas Light -- On behalf of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal for the recovery of costs and funding aspects of Washington Gas Light Company's Revised Accelerated Pipe Replacement Plan. 2014

Case No. EC-123-0082-00 – Entergy Mississippi – On behalf of Mississippi Public Utilities Staff reviewed and testified on the reasonableness of Entergy Mississippi, Inc.'s proposed depreciation rates and cost of service study. 2014

Case 9345 – Maryland Water Services – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2014

Case No. 2013-00167 – Columbia Gas of Kentucky – On behalf of the Office of Rate Intervention of the Attorney General for the Commonwealth of Kentucky testified on the reasonableness of the Company proposed rate increase. 2013

Docket 13-G-1301 – Consolidated Edison – On behalf of US Power Generating Company testified on the reasonableness of proposed modifications to natural gas balancing services. 2013

Docket No. 13-01-09 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2013

Case U-17169 - Semco Energy - On behalf of the Michigan Department of Attorney General testified on the reasonableness of the Company's proposal to modify its accelerated main replacement form for gas distribution facilities. 2013

Docket No. 13-06003 – Sierra Power Company - On behalf of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2013.

Docket No. E-01 933A-I 2-0291 – Tucson Electric Power -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's rate increase. 2012

Case No. FC 1093 - Washington Gas and Light – On behalf of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal to replace and/or remediate certain gas distribution facilities that are subject of this case, 2012.

Docket No. C-2011-2226096 — Pennsylvania American Water Co. - In a class-action lawsuit, testified before the PA PUC on behalf of C. Leslie Pettko on the reasonableness of the surcharges imposed by Pennsylvania American Water Company. 2012

Docket No. 11-06007 – Nevada Power Company – On behalf of the Nevada Public Service Commission, testified on the reasonableness of the Company electric depreciation study on Nevada Power Co. 2011

MEUA –On behalf of the Municipal Electric Utilities Association, filed testimony with the New York Power Authority (NYPA) on the reasonableness of the Authority's 2011 Rate Modification Plan for the Niagara Power Project. 2011

Case No. 9283 – Green Ridge Utilities, Inc. – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2011

Case No. 11-G-0280 – Corning Natural Gas -- On behalf of the Village of Bath, NY, analyzed the construction program, revenue requirement, and rate design proposed by the gas distribution company serving the Village. 2011

Case No. 10-G-0598 – Bath Electric Gas and Water Systems - Testified as to the reasonableness of the Village of Bath's request for a refund relating to overcharges for gas purchased from the Corning Natural Gas Co. 2011

Case No. U-16472 – Detroit Edison -- On behalf of four large hospitals – Detroit Medical Center, Henry Ford Health Systems, William Beaumont Hospital, and Trinity Health Michigan – testified on the reasonableness of the continuation of a service class for large customers with special contracts. 2011

Case No. 9252 – Artesian Water Maryland, Inc. - On behalf of the Maryland Office of People's Counsel, analyzed proposed revenue requirement of Artesian Water Maryland, Inc. 2011.

Case No. 10-E-0362 – Orange and Rockland Utilities, Inc. - On behalf of a coalition of municipalities, testified on the reasonableness of the proposed revenue requirement of Company. 2010.

Docket No. 05-10-RE04 – Connecticut Light and Power Co. – On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the assist in its review of the application of Company for approval of full deployment of its Advance Metering Infrastructure ("AMI"). 2010

Docket Nos. 10-06003 and 10-06004 – Sierra Power Company - On behalf of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2010.

Case No. 10-E-0050 – Niagara Mohawk Power Corporation -- On behalf of a coalition of municipalities, testified on the reasonableness of utility's proposal to eliminate contracts to provide street lighting service. 2010

Case No. 9248 – Maryland Water Services - On behalf of the Maryland Office of the People's Counsel, testified on the reasonableness of the proposed revenue requirement of Maryland Water Services, Inc. 2011

Docket No. 10-12-02 – Yankee Gas Services Company -- On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the Company's proposed depreciation rates. 2010

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities, Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 – Connecticut Water Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 – Connecticut Light & Power Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel of the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 -- UNS Gas, INC. -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 – Arizona Public Service – On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in depreciation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 – Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdrola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 -- Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 -- Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2012 – Speaker accelerated main replacement programs

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association
Northeast Public Power Association
New York State Independent System Operator

EXHIBIT FWR-2

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 28, 2016

RUCO 8.06

Hutchens Direct 13:11-24 – 18:1-18 - Please provide the monthly energy sales for TEP's retail delivery customers from January 2006-December 2015 on an actual basis and weather normalized basis.

RESPONSE:

Please see RUCO 8.06.xlsx for the monthly weather normalized sales. The Excel file is not identified by Bates numbers.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-3

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 28, 2016

RUCO 8.05

Hutchens Direct 13:11-24 – 18:1-18 - Please provide the monthly peak demand for TEP's retail delivery customers from January 2006-December 2015 on an actual basis and weather normalized basis.

RESPONSE:

Please see file RUCO 8.05 City Load Data.xlsx, sheet "Monthly Summary" for the monthly peak data requested. The Excel file is not identified by Bates numbers. The Company cannot provide weather normalized peak data as it does not perform such adjustments. This is because the peak model has a high degree of complexity, thus making peak normalizing very difficult and normalized peak values are of little value for system planning.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-4

CONFIDENTIAL

EXHIBIT FWR-5

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tucson Electric Power Company	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Salt River Project Agricultural	LF	Tariff 3 S.A. 12			
2	Improvement and Power District					
3	Navajo Tribal Utility Authority	LF	Tariff 3 S.A. 11			
4	Tohono O'odham Utility Authority	LF	Tariff 3 S.A. 13			
5	Shell Energy North America (US) LP	LF	WSPP			
6	EDF Trading North America, LLC	LF	ISDA			
7	Trico Electric Cooperative	LF	Tariff 3 S.A. 13			
8	Ajo Improvement District	SF	AJO Contract			
9	Morenci Water and Electric	SF	Morenci Agreement			
10	Arizona Electric Power Cooperative	SF	WSPP			
11	Arizona Public Service Company	SF	WSPP			
12	Black Hills Power, Inc.	SF	WSPP			
13	BP Energy Company	SF	ISDA			
14	Cargill Power Markets, LLC	SF	ISDA			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

- Privileged Data

EXHIBIT FWR-6

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC TWELFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 May 2, 2016

AECC 12.4

Please identify the margins earned by TEP on the Shell Long Term Energy Sales contract for each month since its effective date.

RESPONSE: **April 19, 2016**

The Company objects to this question as it relates to non-ACC jurisdictional margins that are outside the scope of this rate case.

RESPONDENT:

Jeanine Tracey

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: **May 2, 2016**

Per discussions between counsel for the Company and counsel for AECC, please see AECC 12.4-12.6 4-12-16 (Test Year)-Competitive Sensitive Confidential.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

The Shell contract was put into place after the acquisition of Gila River Unit 3. The contract expires December 31, 2017.

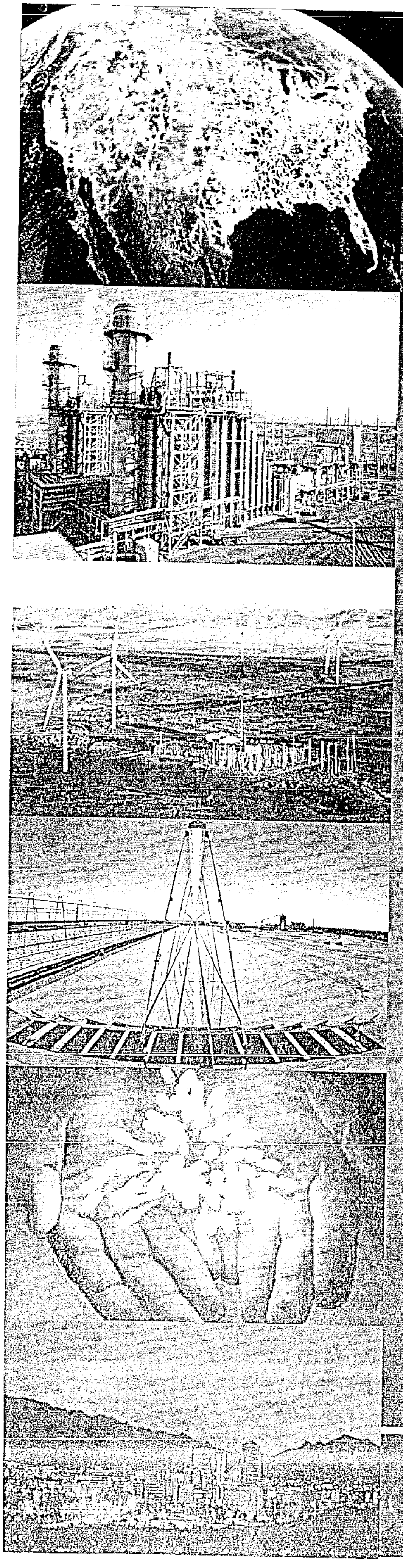
RESPONDENT:

Jeanine Tracey / Michael Sheehan

WITNESS:

Dallas Dukes

EXHIBIT FWR-7



TUCSON ELECTRIC POWER

2014 Integrated Resource Plan

April 1, 2014

Firm Wholesale Energy Forecast

In addition to retail sales directly to customers, TEP is currently under contract to provide wholesale energy to three utility customers:

1) Salt River Project (SRP) through May 2016
2) Navajo Tribal Utility Authority (NTUA) through December 2022
3) Tohono O'odham Utility Authority (TOUA) through December 2015

TEP expected firm wholesale obligations are shown in Table 6 below. It is important to note contract extensions have not been assumed. However, there is a possibility that any or all agreements could be extended. This would obviously require current resource plans to be revised to account for the additional energy sales and peak summer load requirements.

Table 6 - Firm Wholesale Requirements

Firm Wholesale, GWh	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SRP	491	491	205	0	0	0	0	0	0	0	0
NTUA	234	239	249	256	264	272	280	287	294	0	0
TOUA	27	19	0	0	0	0	0	0	0	0	0
Total Firm Wholesale	753	749	454	256	264	272	280	287	294	0	0

Peak Demand, MW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SRP	100	100	100	0	0	0	0	0	0	0	0
NTUA	17	17	33	33	33	33	36	43	43	0	0
TOU	3	3	0	0	0	0	0	0	0	0	0
Total Firm Demand	120	120	33	33	33	33	36	43	43	0	0

EXHIBIT FWR-8

CONFIDENTIAL

EXHIBIT FWR-9

CONFIDENTIAL

EXHIBIT FWR-10

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.03

Weather Normalization – Please provide the results and adjustment to test-year revenue by year under the Company's new model if a nine year, eight year, seven year, six year, five year, four year, and three year model were used. In addition, please provide the statistical outputs, such as p-values and r-squared values associated with each year requested above.

RESPONSE:

The Company objects to the request as it is overly burdensome. The time required to generate each of the models above and to calculate the total adjusted revenue is significant. Please see RUCO 7.05b for an explanation as to why this process is highly burdensome and resource intensive.

For the model statistics of the model the Company used for the weather normalization, please see file RUCO 7.03 TEP Weather Normalization Model Statistics.pdf, Bates Nos. TEP\021852-021889.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.04

Weather Normalization – Please provide the results and adjustment to test-year revenue under the Company's new model if a fifteen year, twenty year, twenty five year and thirty year model were used. In addition, please provide the statistical outputs, such as p-values and r-squared values associated with each year requested above.

RESPONSE:

Please refer to RUCO 7.03.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

EXHIBIT FWR-11

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.11

Residential Customers - RE: Dukes Direct at page 11:22-25, please provide the following:

a. the number of seasonal residential customers that TEP has together with their energy use, by month, for a typical year;

b. the number of year round residential customers that TEP has together with their energy use, by month, for a typical year;

c. the estimated number of residential vacant homes, by month, for the years 2011-2015.

d. Please provide typical load profiles for a residential seasonal customer, a residential vacant home, a residential year round customer, and a residential customer with distributed generation. The load profiles should be for the winter period, the summer period, and the peak day.

RESPONSE:

a./b. The Company does not currently track seasonal versus year round customers and therefore does not have their energy use as requested.

c. The Company does not track vacant homes.

d. For the reasons above, the company does not have load profiles for the requested customer types. The company has a large swath of hourly data for a number of customers which include some of the customer types listed. Although there are not distributed generation customers in the sample, the Company is also including the NREL SAM 8760 production curve for the Tucson area for use in estimating solar DG customer hourly load shapes.

Please see the following files for the 8760 production curve.

File Name	Bates Numbers
RUCO 7.11 Individual Customer Sample 2-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 3-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 4-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 5-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample-Confidential.xlsx	N/A
RUCO 7.11 NREL SAM DATA-Confidential.xlsx	N/A

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-12

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 28, 2016

RUCO 8.04

Re: Response to RUCO 3.11 and Dukes Direct at 14:6-9 - FERC Form 1 data shows that the UPC for Residential rate class has been declining since 2007 when it peaked at 10,922 kWh per year (See 2007 FERC Form 1, page 304, column e, line 2). For 2007 please provide the weather normalized UPC. For each year 2008-2015, please provide the actual annual UPC for the Residential Regular service class together with the UPC change due to DG, due to energy efficiency and due to economic changes.

RESPONSE:

Please see the table below for the breakout of weather normalized residential UPC and the change due to EE and DG. Please note, when the Company performs the weather normalization, that the Company weather normalizes the entire residential class and not just R01. This is why the Company is starting with the 2007 UPC of 11,129 instead of 10,922. The Company cannot accurately quantify what is due to economic changes versus some other effect. Thus the values are labeled as other changes.

Year	Residential UPC	Weather Normalized UPC	Y/Y EE Change	Y/Y DG Change	Y/Y Other Change
2007	11,129	10,956			
2008	10,621	10,802	(9)	(2)	(144)
2009	10,708	10,713	(24)	(3)	(62)
2010	10,579	10,579	(45)	(7)	(82)
2011	10,606	10,450	(140)	(29)	40
2012	10,375	10,350	(174)	(32)	106
2013	10,424	10,108	(182)	(50)	(10)
2014	9,960	9,805	(265)	(38)	1
2015	9,894	9,684	(231)	(78)	189

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-13

RUCO 7.20

TEP Headquarters – Please answer the following questions as they relate to the TEP Headquarters:

a. Based on the Company's last rate case the Company identified the following two components of building costs:

TEP New HQ-IT	$ 7,363,145
TEP New HQ-Facilities	$ 84,604,455
Total	$ 91,967,600

Please update these two cost components to reflected other capital improvements and/or additions. Further, update the response for any other capitalized cost component not already reflected in these two components. In addition, include the FERC sub account numbers for these capitalized assets and amounts (e.g. 311 Structures and Improvements).

b. Based on the Company's last rate case the Company identified the following cost per square foot.

Office	$263/sf
Retail	$178/sf
Parking	$64/sf

Please update these costs to reflect the current cost per square foot for the above three areas. In addition provide the work sheets, and calculations to substantiate the response.

c. Do the dollar per square foot (Office, Retail, Parking) cited in b. include a capitalized portion and an operating and maintenance ("O&M") expense portion?

d. If no to c. provide the capitalized portion and the O&M portion per square foot. Further providing a listing of components that are listed in the capitalized and O&M portions (e.g. property taxes, depreciation expense, etc.).

e. Based on the Company's last rate case, the Company indicated that 12,000 gross square feet of retail space was unused. Please update the gross square feet of retail space to reflect both used and unused space.

f. Based on the Company's last rate case, the Company indicated that 8,540 gross square feet of vacant and unused cubical space. Please update the gross square feet of office space to reflect both used and unused space.

g. Please provide the gross square feet of parking space to reflect both used and unused space.

h. List by floor and square footage the portion of the building that has been allocated to TEP employees, UNS electric employees, UNS gas employees, and any other TEP affiliates.

i. List by floor and square footage the portion of the building that is rented/leased to other non-affiliate entities (e.g. insurance company)?

j. Is a profit component built into the rental/lease payment that each affiliate member pays to the parent company, if so, what is that percentage, and what is the amount of profit charged to each affiliate member?

k. Is a profit component built into the rental/lease payment that each non-affiliate member pays to the parent company, if so, what is that percentage, and what is the amount of profit charged to each non-affiliate member?

RESPONSE: **April 18, 2016**

TEP is in the process of gathering this information and will provide it as soon as possible

RESPONDENT:

Anne Liu

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: **May 2, 2016**

a. The cost components for the TEP Headquarters at June 30, 2015 are as follows:

FERC Sub Account	Description	Net
E397	Communication Equipment	$ 714,308
E391-CP	Computer Equip.	3,574,387
	TEP HQ-IT Total	4,288,695
E390	Structures & Improvements-General Plant	68,371,896
E391-OE	Office Equip	1,331,752
E389-LD	Land	8,549,938
E398-RW	Right a ways	41,468
	TEP HQ-Facilities Total	78,295,053
	Total at June 30, 2015	$ 82,583,748

b. The cost per square foot provided in the last rate case was an approximation based on total construction costs and gross square footage. Construction costs included land, direct construction costs for shell building, permits, impact fees, etc. For your reference, please see file RUCO 7.20.pdf, Bates Nos. TEP\023766-023770, for the response to STF 22.06 (r) provided in the 2012 TEP Rate Case.

The net balance of the HQ Building decreased by 11.62% as compared to the balance in the last rate case. To provide an approximation of the current cost per square feet, the prior amounts were decreased accordingly.

	June 30, 2015	Dec. 31, 2011	Change
Cost	98,679,260	94,745,693	
Reserve	(16,095,511)	(1,300,437)	
Net Balance	82,583,748	93,445,256	-11.62%

	Cost Per Square Ft - Adjusted by % Change	
	Prior Rate Case	Current
Office	263	232
Retail	178	157
Parking	64	57

c. No, it does not include an O&M expense portion. The cost per square foot figures in the last rate case were based on capitalized one-time construction costs. It included land costs, direct construction costs, and one time sales tax/ plans, permits and impact fees.

d. The Company does not maintain dollar per square foot data by Office, Retail, Parking for capitalized and O&M expenses. As noted above, the total capitalized portion of the building is $82,583,748 at June 30, 2015.

Expenses for the test year by component are:

O&M Expense	1,657,958
Property Taxes	1,111,450
Depreciation	3,881,648
	6,651,056

e. The 12,000 square footage of retail space supplied in the last rate case should be revised to 10,185. It is 100% unused.

f. The square footage of space built out excluding retail and the garage levels is 267,625. This includes workstations, offices, hallways, common areas, rest rooms, mechanical rooms, etc. Of the 267,625 total square footage, 263,365 square feet is used. 4,260 square feet is unused workstation and office space.

g. The square footage of the parking space is 224,600. 100% used.

h. The headquarters building is 100% occupied by TEP employees or contract personnel doing work on behalf of TEP, UNS Electric and UNS Gas.

i. None of the headquarters building is currently being rented/leased to others.

j. There are no rental/lease payments from affiliate members for the headquarters as the building is 100% occupied by TEP. However, within the building allocation cost charged to affiliates, through a labor allocation; a return component of 5.04% as per the agreed upon return in the last rate case.

k. Not applicable. There are no rental/lease payments paid by non-affiliated members.

RESPONDENT:
Anne Liu (a, b, c, d, h-k) / Ryan Companies (e, f, g)
WITNESS:
Dallas Dukes

EXHIBIT FWR-14

RUCO 7.13

Did TEP conduct a comprehensive cost-benefit analysis of building a new headquarters versus maintaining the existing facilities? If so, please provide the analysis. If not, why not?

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

The Company did an extensive evaluation before it decided to proceed with a new headquarters building. Management began considering adding and consolidating office space in mid-2007; a final decision to purchase the land for a new building was made in April 2009 and a final decision to begin building was made in October 2009. TEP was considering new space for numerous reasons including:

a. Even with the use of the temporary office trailers, the current facilities were at 99% occupancy and, in certain cases, TEP needed to rent space for project teams;

b. The lease at One South Church, where 80 employees were located, was up for renewal in June 2011;

c. Over 300 employees at the Irvington Campus were housed in 12 temporary office trailers that were costly to operate, and the employees were functionally separated from the other work groups;

d. Two permanent office facilities at the Irvington site (one built in the 1950's and one in the early 1980's) were due for renovation and mechanical upgrades (i.e., HVAC, bathrooms, ADA compliance, etc.);

e. TEP needed more conference space and larger conference/auditorium to facilitate employee meetings—at the time, the largest conference room could only handle 125 people, a small percentage of our employees based in Tucson at that time;

f. For compliance and business continuity reasons, the Company was evaluating backup locations for its IT data center, call center, control room and physical security. TEP met the need for backup facilities by incorporating them into the new secure headquarters.

g. The decision to proceed in the 2009-2010 time frame, which coincided with the weak economy, provided the opportunity to build a new headquarters at a reasonable lower cost level and support construction related jobs in Tucson;

Given the Company's situation, it developed objectives and a plan to resolve the long term office needs. The primary objectives included: a) eliminate existing capacity constraints and provide for growth; b) consolidate employees into fewer office locations to improve communications and reduce travel time and costs; c) consolidate all or at least a major portion of the corporate staff functions into one building to improve communications and reduce travel time and costs; d) choose office location(s) and parking that is convenient and safe for employees; and e) manage costs. In addition to the primary objectives, the Company also wanted to choose an office facility that was environmentally friendly (i.e., incorporating energy efficiency and renewable energy resources) and supported the Tucson community with economic development and/or office common facilities that could be used by the community including local charities.

To meet the objectives, the Company investigated and evaluated various alternatives. It compared the alternatives of a) expanding/remodeling current facilities; b) leasing additional space at One South Church Avenue; c) leasing existing office space at other Tucson locations; d) buying existing office space in Tucson; and e) building a new office building at numerous locations in Tucson. Please see the files listed below for the confidential materials that set forth the analyses conducted in connection with these options and the ultimate decision to build the new corporate headquarters.

File Name	Bates Numbers
RUCO 7.13 New Building Pres 2008 08-2011 12-Confidential.pdf	TEP\027864-027949
RUCO 7.13 NewBuildPresExh2009 04-HumanImpact-Confidential.pdf	TEP\027950-027978
RUCO 7.13 NewBuildPresExh2009 04-Irvington Modulars-Confidential.pdf	TEP\027979-027981
RUCO 7.13 NewBuildPresExh2009 04-ListDscrpProps-Confidential.pdf	TEP\027982-028006
RUCO 7.13 NewBuildPresExh2009 04-Map187482-Confidential.pdf	TEP\028007-028008

Based on the analyses and TEP's needs, it was ultimately determined that the best alternative was to build a corporate headquarters at 88 East Broadway. The key drivers in the decision were: a) there was not suitable existing office space of at least 100,000 square feet with parking for 250 employees available in Tucson; b) building a new building allowed the Company to design for its specific use and needs; c) building a new building allowed the facility to be sized to consolidate a larger number of employees into one location based on a space planning/adjacency study (see Response to RUCO 7.12); d) the downtown location is convenient for employees for commuting including access to public transportation and the downtown location supports the development of downtown Tucson; and e) the slow economy and weak construction industry allowed the company to closely manage costs, to build the facility in a short, tight time period and to provide jobs/economic activity to the local Tucson economy.

RESPONDENT:

Scott Rathbun/Kevin Larson

WITNESS:

Michael DeConcini

EXHIBIT FWR-15

CONFIDENTIAL

EXHIBIT FWR-16

CONFIDENTIAL

EXHIBIT FWR-17

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
November 7, 2012

RUCO 7.23

When was ownership of the new facility transferred to Tucson Electric Power Company from UniSource, and why did this transfer occur?

RESPONSE:

The transfer date was November 1, 2011. The building was initially owned by UNS to provide greater flexibility in financing the asset construction. The transfer of ownership made economic and practical sense for many reasons, including:

1. UNS initially attempted to attain New Markets Tax Credits for the building, which were available for development in certain areas. The credits were available to a developer/lessor (a role UNS could have fulfilled by owning the building and leasing it to TEP), but were not available to an owner occupant such as TEP. When it became clear that the tax credits would not be available for this development project, it made more economic sense for TEP to own the asset directly rather than UNS (see additional reasons below).
2. TEP avoided a potential liability on its balance sheet by owning the asset instead of entering into a long-term lease obligation;
3. Use of the facility by TEP was ensured over the long-term, avoiding the need to consider purchase and lease renewal options at end of the lease term; and
4. Long-term financing for the facility could be obtained on better terms at TEP due to TEP's investment-grade credit rating (UNS is rated Ba1, a non-investment grade credit rating).

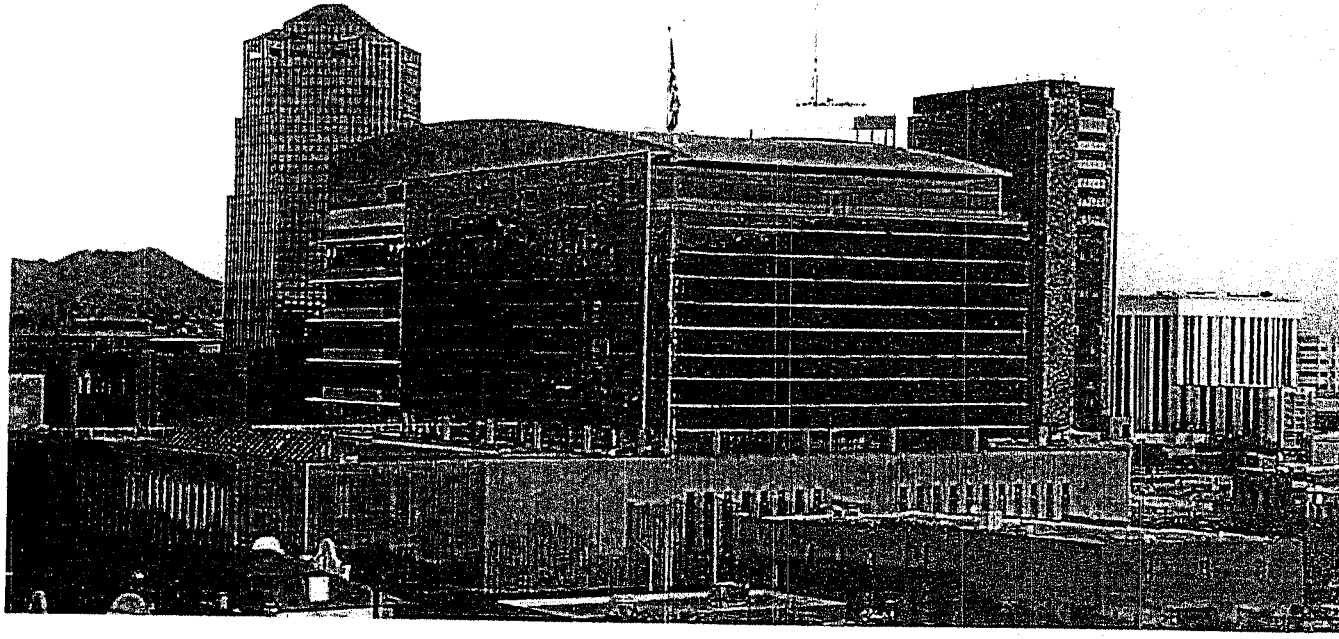
RESPONDENT:

Scott Rathbun, Karen Kissinger and Kentton Grant

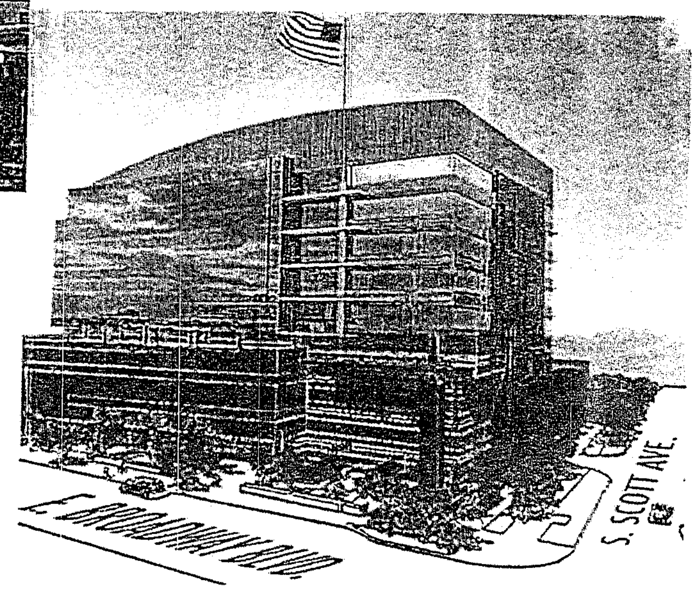
WITNESS:

Michael DeConcini

EXHIBIT FWR-18



There's a New Energy Downtown



UniSource Energy's solar-powered, energy-efficient Tucson headquarters

BRIGHT SOLUTIONS™
from UniSource Energy

UniSource Energy's corporate headquarters is a showcase of green construction and design. Completed in November 2011, the building supports the efficient, effective operations of Tucson Electric Power (TEP) and UniSource Energy Services (UES) UniSource Energy's utility subsidiaries.

The nine story building provides 232,000 square feet of space for more than 500 employees. It also includes 11,000 square feet of ground-floor retail space, a state-of-the-art conference center, on-site parking and a long list of environmentally responsible features.

UniSource Energy's corporate headquarters exemplifies the company's commitment to leadership in energy efficiency and renewable energy.

For more information about the green programs available to UniSource Energy's utility customers, visit tep.com or uesaz.com.

BRIGHT SOLUTIONS™
from UniSource Energy

EXHIBIT FWR-19

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2009

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________ to ________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	UNISOURCE ENERGY CORPORATION (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	TUCSON ELECTRIC POWER COMPANY (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation	Yes þ	No o
Tucson Electric Power Company	Yes o	No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation	Yes o	No þ
Tucson Electric Power Company	Yes þ	No o

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such

Table of Contents

Cash used for investing activities is primarily a result of capital expenditures at TEP, UNS Gas and UNS Electric. Cash used for investing and financing activities can fluctuate year-to-year depending on: capital expenditures, repayments and borrowings under revolving credit facilities; debt issuances or retirements; capital lease payments by TEP; and dividends paid by UniSource Energy to its shareholders.

Operating Activities

In 2009, net cash flows from operating activities were $70 million higher than 2008 primarily due to: lower costs of fuel and purchased energy; increased retail revenues due to base rate increases at TEP and UNS Electric and hot summer weather; lower interest paid on capital leases and long-term debt; partially offset by lower wholesale sales, higher O&M and higher wages paid.

Investing Activities

Net cash used for investing activities was $156 million lower in 2009 compared with 2008 due to: a $133 million deposit made by TEP last year with the trustee for bonds that matured on August 1, 2008; and a $70 million decrease in capital expenditures in 2009; partially offset by a $31 million investment made by TEP in 2009 to purchase Springerville lease debt; and a $12 million decrease in proceeds from investment in lease debt.

Capital Expenditures

Business Segment	Actual 2009	Estimated 2010	2011	2012	2013	2014
	-Millions of Dollars-					
TEP	$ 235	$ 258	$ 217	$ 203	$ 225	$ 209
UNS Gas	14	14	16	16	16	18
UNS Electric	28	26	25	31	13	16
UniSource Energy Stand-Alone	10	16	27	1	—	1
UniSource Energy Consolidated	$ 287	$ 314	$ 285	$ 251	$ 254	$ 244

- Included in TEP's capital expenditures forecast for 2010 is $52 million for the proposed purchase of Sundt Unit 4.
- Items excluded from TEP's capital expenditures forecast are: the estimated cost to construct proposed Tucson to Nogales, Arizona transmission line of $120 million; estimated costs of $300 million between 2011-2014 to construct 75 to 150 MW of local generation that may be required in 2015.
- The estimated capital expenditures for UniSource Energy Stand-Alone are for the purchase of land and construction of a new corporate headquarters.

For more information see *TEP, Liquidity and Capital Resources, Investing Activities, Capital Expenditures,* below, and *Item 1. Business, TEP, Transmission Access, Tucson to Nogales Transmission Line,* above.

Financing Activities

Net cash proceeds from financing activities were $170 million lower in 2009 compared with 2008. In 2008, The Industrial Development Authority of Pima County issued, for the benefit of TEP, approximately $221 million of tax-exempt industrial development revenue bonds and UNS Electric issued $100 million of long-term debt used in part to refinance a $60 million debt maturity. Factors affecting proceeds from financing activities in 2009 included: $30 million of proceeds from the issuance of short-term debt at UED; a $70 million decrease in payments of long-term debt compared with 2008; a $50 million decline in payments on capital lease obligations compared with 2008; and a $7 million increase in dividends paid compared with 2008.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2010

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	UNISOURCE ENERGY CORPORATION (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	TUCSON ELECTRIC POWER COMPANY (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation	Yes þ	No o
Tucson Electric Power Company	Yes o	No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation	Yes o	No þ
Tucson Electric Power Company	Yes þ	No o

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

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Capital Expenditures Forecast

Business Segment	Actual 2010	2011	2012	Estimated 2013	2014	2015
			-Millions of Dollars-			
TEP	$ 267	$ 306	$ 273	$ 372	$ 322	$ 286
UNS Gas	10	12	11	14	16	22
UNS Electric (1)	22	37	51	25	30	32
Other Capital Expenditures	17	36	1	—	—	—
	$ 316	$ 391	$ 336	$ 411	$ 368	$ 340

(1) UNS Electric is expected to purchase BMGS from UED for approximately $62 million during 2011. Since this is an inter-company transaction, it is not included in the chart, as it is eliminated from UniSource Energy consolidated capital expenditures. See *UNS Electric, Factors Affecting Results of Operations, Rates, 2010 UNS Electric Rate Order*, below, for more information.

TEP's capital expenditures in 2010 include $52 million for the purchase of Sundt Unit 4. TEP's estimated capital expenditures in 2015 exclude the potential purchase of Springerville Unit 1 and Springerville Coal Handling Facilities upon the expiration of their respective leases in January 2015.

Other capital expenditures reflect UniSource Energy's standalone capital expenditures, including the purchase of land and construction costs for a new corporate headquarters.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to changes in business conditions, construction schedules, environmental requirements, state or federal regulations and other factors.

For more information regarding TEP's capital expenditures, see *Tucson Electric Power Company, Liquidity and Capital Resources, Investing Activities, Capital Expenditures*, below.

Financing Activities

Net cash proceeds used for financing activities were $22 million higher in 2010 than they were in 2009 due to:

- $30 million of net revolving credit facility repayments in 2010 compared with net proceeds of $5 million in 2009;
- a $32 million increase in payments of capital lease obligations;
- $30 million of short-term debt proceeds in 2009 compared with none in 2010; and
- a $15 million increase in dividends paid to common shareholders; partially offset by
- an $82 million increase in proceeds from long-term debt net of repayments of long-term debt.

Capital Contributions

In the first quarter of 2010, UED paid a $9 million dividend to UniSource Energy, of which $4 million represented a return of capital distribution. In March 2010, UniSource Energy contributed $15 million in capital to TEP to help fund the purchase of Sundt Unit 4.

In 2009, UED paid a $30 million dividend to UniSource Energy which also represented a return of capital distribution. UniSource Energy used the proceeds to contribute $30 million of capital to TEP to purchase lease debt related to Springerville Unit 1.

See *Other Non-Reportable Business Segments, UED* and *Tucson Electric Power Company, Liquidity and Capital Resources*, below for more information.

UniSource Credit Agreement

In November 2010, UniSource Energy amended and restated its existing credit agreement (UniSource Credit Agreement). The UniSource Credit Agreement had previously included a $30 million term loan facility and a $70 million revolving credit facility. As amended, the UniSource Credit Agreement consists of a $125 million revolving credit and revolving letter of credit facility. The UniSource Credit Agreement will expire in November 2014. At December 31, 2010, there was $27 million outstanding at a weighted average interest rate of 3.26%.

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322 et al.

UNREDACTED DIRECT TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 3, 2016

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EXECUTIVE SUMMARY

The Company's presentation is a study in contrasts. On the one hand, Company President David Hutchens testified that the impact of EE and DG on the Company's retail electric sales has been significant noting that energy efficiency and distributed generation reached nearly 1,000,000 MWh, which equates to about 11% of TEP's test year sales. On the other hand, the Company has acquired 413 MW of Gila River Unit #3 and in 2015, the Company's growing renewable energy portfolio (including DG) is expected to expand to over 500 megawatts as compared to 56 MW in the Company's last rate proceeding.

On the one hand the Company has been told that its load forecasts appear to be optimistic in that is assumes a rapid return to historical load growth and the ACC Staff recommended that TEP reexamine their load forecasting techniques. Yet, Company President David Hutchens states that from the period of January 1, 2012 to June 30, 2015, TEP invested approximately $1.3 billion in order to continue providing its customers with safe and reliable service. On a net plant basis for retail customers these investments increase rate base from $1.5 billion in the last case to $2.1 billion in this case an increase of 40%. The Company does not seem to understand its building for load that under current market conditions is unlikely to return.

The Company is asking for a large amount of outstanding issues to be addressed in this case and the cost of them is large. Gila River Unit 3 is being placed in rate base. The Company wants to recover the increased cost for Springerville Unit 1 in the fuel adjustment clause. The Company seeks full cost recovery of the stranded assets related to the Sundt Coal Handling facilities and the pending retirement of San Juan Unit 2. The Company seeks to shorten the service life of San Juan Unit 1 because of problems that may or may not occur almost a decade from now.

I propose a series of adjustments to the Company's presentation. The first addresses the capacity acquisition issue. When the Company has excess capacity, it sells it in the wholesale market to recover some of the costs for supporting that capacity. This is done under FERC approved wholesale power contracts. The Company's presentation removes some of the sales unjustly and I propose an adjustment which is more reflective of conditions that occurred in the test year and appear likely to reoccur in the year following when rates are reset, 2017.

My second adjustment is to depreciation. Here I propose two adjustments. The first is to reject the shortening of the service life for San Juan Unit 1. The Company has no firm basis to make this adjustment and given the rate impact, an almost $13 increase in depreciation expense, and the fact that the Company is asking ratepayers to pay for so many other things in this case, I believe the Company's proposed shortening of the service life is premature.

My third adjustment relates to the recovery of post-test year plant. Based on past precedent in this State, post-test year plant might be allowed for recovery in rates when the plant is necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making. This Company has a history of being overly optimistic in its load projections and has been asked to review this by Commission Staff. Moreover, when the Company is asked about basic information about its residential customers, which constitute 90% of its customer base, it claims to have little knowledge. Yet, with its propensity for spending, the Company continues to build projects for forecasted load growth that has yet to materialize. I don't believe that the Company has shown that its decisions reflect appropriate, efficient, effective, and timely decision-making and as such, propose to remove post-test year plant for ratemaking purposes.

My fourth adjustment relates to the third, and that is the Company's proposed adjustment for residential test year sales for weather normalization. As noted above the Company claims it has little knowledge about its customers and this brings into question the accuracy of attributing any sales variation to weather as opposed to economic conditions. I propose to only allow half of the proposed weather normalized sales variation for residential customers to be allowed in rates.

My fifth and final adjustment relates to the UNS headquarters building. TEP's parent corporation, UNS, conceived and built this building in the downtown location. The downtown location was critical because UNS was trying to gain investment tax credits which would have garnered the parent Company considerably financial benefit. When the tax credits became unavailable and after construction of the new building was complete and the employees were about to move into the building, ownership was transferred from the non-regulated entity, UNS, to the regulated entity, TEP, which happened to be filing for a rate case shortly thereafter. Effectively, the parent is attempting to shift the cost burden and risk associated with it from its shareholders to TEPs ratepayers. When UNS was allowed to form a holding Company back in 1997 there was a safeguard provision to ensure that the formation of the Holding Company structure would not result in adverse consequences to TEP. That provision was that the parent company would charge the lower of embedded costs or the prevailing market rent for any exchange of goods between the parent company and the affiliate. Since the market rent in Tucson is considerably less than the embedded cost of the building, for ratemaking purposes, I propose to reflect this provision of the holding company order into the rate setting process. This would be effectuated by removing the building from TEP's rate base, removing the associated expenses and imputing a market based rent.

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services in electric, gas and water utility industry matters, and specializing in the fields of rates, planning and utility economics. My office address is 235 Lark Street, Albany, New York 12210.

Q. PLEASE DESCRIBE THE HUDSON RIVER ENERGY GROUP.

A. The Hudson River Energy Group ("HREG") is an engineering consulting firm specializing in the fields of rates, planning, economics and utility operations for the electric, natural gas, steam and water utility industries. HREG was founded in 1998 and has served a wide variety of clients including municipal utilities, government agencies, state commissions, consumer advocates, law firms, industrial companies, power companies, and environmental organizations. HREG conducts rate design and cost of service studies, and designs performance based rate plans. HREG also assists clients in handling the complexities of deregulation and restructuring, including Open Access Transmission Tariff pricing, unbundling of rates, resource adequacy, transmission planning policies and power supply. During HREG's existence, we have proffered our expertise before the Federal Energy Regulatory Commission ("FERC" or "Commission") and a large number of state utility regulatory commissions across the country.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now known as "Clarkson University") in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Public Service Commission ("NYPSC") in the Rates and System Planning sections of the Power Division. My responsibilities included, resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the state. These duties also encompassed rate design, performing embedded and marginal cost of service studies, as well as depreciation studies.

Before leaving NYPSC, I was responsible for directing all engineering staff during major proceedings, including those relating to rates, integrated resource planning ("IRP") and environmental impact studies. In February 1997, I left NYPSC and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own consulting firm.

In my 35 years of experience, I have testified as an expert witness in utility rate proceedings on more than one hundred occasions before various utility regulatory bodies, including: the Arizona Corporation Commission, the Connecticut Department of Public Utility Control (now the Connecticut Public Utilities Regulatory Authority), the Delaware Public Service Commission, the Illinois Commerce Commission, the Kentucky Public Service Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the Mississippi Public Service Commission, NYPSC, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, and the FERC. Currently, I advise a variety of regulatory commissions, consumer advocates, municipal utilities, and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A summary of my professional qualifications and experience, including a listing of cases in which I have proffered testimony, is attached as Exhibit__FWR-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO").

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

SCOPE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked to review the engineering justification and ratemaking need for certain revenue requirement aspects of the Tucson Electric Power Company's ("TEP" or "the Company") rate request.

Q. HAVE YOU PREPARED AND EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes, I have prepared the following:

Exhibit-FWR-1 - Resume of Frank W. Radigan

Exhibit-FWR-2 - Response to RUCO 8.06
Exhibit-FWR-3 - Response to RUCO 8.05
Exhibit-FWR-4 – Confidential Response to Staff 3.3
Exhibit-FWR-5 - Excerpt from TEP 2015 FERC Form 1
Exhibit-FWR-6 - Response to AECC 12.4
Exhibit-FWR-7 - Excerpt from TEP 2014 IRP
Exhibit-FWR-8 - Confidential Planning Memorandum for Canoa Ranch
Exhibit-FWR-9 - Confidential Planning Memorandum for Lateral
Exhibit-FWR-10 - Responses to RUCO 7.3 and 7.4
Exhibit-FWR-11 - Responses to RUCO 7.11
Exhibit-FWR-12 - Response to RUCO 8.04
Exhibit-FWR-13 - Response to RUCO 7.20
Exhibit-FWR-14 - Response to RUCO 7.13 in 2012 Rate Case
Exhibit-FWR-15 - Confidential Extract from Response to RUCO 7.13 from 2012 TEP Rate Case
Exhibit-FWR-16 - Confidential Presentation on Tax Credits

Exhibit-FWR-17 - Response to RUCO 7.2 from 2012 TEP Rate Case
Exhibit-FWR-18 - New Headquarters Brochure
Exhibit-FWR-19 - Excerpts from UNS' 10-Ks for 2009 and 2010

SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's presentation is a study in contrasts. On the one hand, Company President David Hutchens testified that the impact of EE and DG on the Company's retail electric sales has been significant (Hutchens Direct at 7). He notes that since 2012, cumulative sales reductions attributable to energy efficiency and distributed generation reached nearly 1,000,000 MWh, which equates to about 11% of TEP's test year sales (Ibid). On the other hand, the Company has acquired 413 MW of Gila River Unit #3 and in 2015, the Company's growing renewable energy portfolio (including DG) is expected to expand to over 500 megawatts ("MW") as compared to 56 MW in the Company's last rate proceeding (Hutchens Direct at 6-7). In addition, customer installed solar applications continue unabated at approximately 2 MW a month and now total approximately 180 MW (Ibid).

On the one hand the Company has been told that its load forecasts appear to be optimistic in that is assumes a rapid return to historical load growth and the ACC Staff recommended that TEP reexamine their load forecasting techniques[1]. Yet, Company President David Hutchens states that from the

[1] **DOCKET NO. E-00000V-13-0070 -** Staff'statewide review and assessments of the integrated resource plans, filed on December 19, 2014, page 114.

period of January 1, 2012 to June 30, 2015, TEP invested approximately $1.3 billion in order to continue providing its customers with safe and reliable service (Hutchens Direct at 25). On a net plant basis for retail customers these investments increase rate base from $1.5 billion in the last case[2] to $2.1 billion in this case (Schedule B) an increase of 40%. The Company does not seem to understand its building for load that under current market conditions is unlikely to return.

Company witness Dallas Dukes testifies that use per customer, since 2011, TEP has seen a decline of approximately 7.5% in just the residential customer class alone (Dukes Direct at 14). Yet, Company President Hutchens testifies that TEP expects to **supply at least 30 percent of TEP's** energy from renewable resources by 2030 – <u>doubling the level the Company must achieve by 2025 under Arizona's RES Hutchens Direct at page 7</u> and Sheehan Direct footnote 41 at page 32, emphasis added). The obvious question here is why is the going so far above and beyond investing in plant if it must be spread over a smaller base?

On the one hand, Company President Hutchens states that the recent Gila River acquisition is part of a strategy to reduce reliance on coal [3]but this 413

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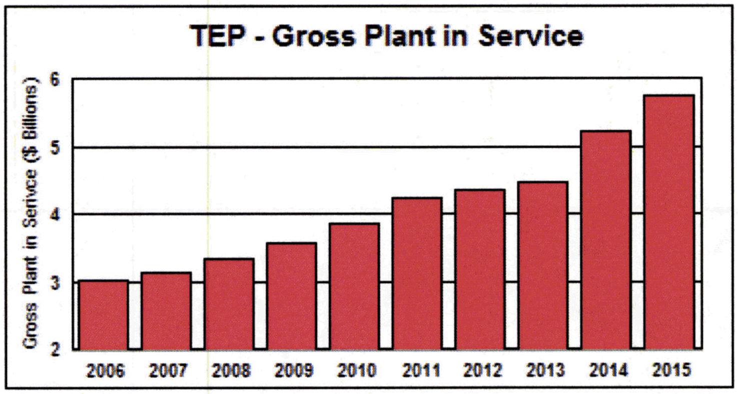
[2] Docket No. E-01933A-12-029, Settlement Agreement, Attachment A, under Column titled Settlement, Row titled rate base.

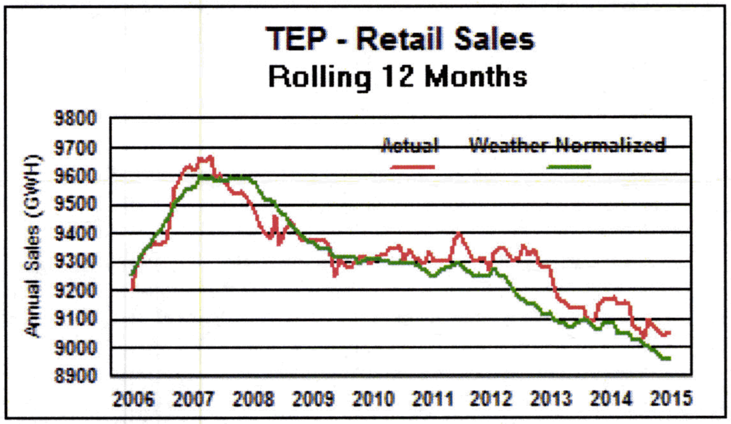
[3] Hutchens Direct at 7.

MW acquisition did not replace the 156 MW Sundt 4 since that unit simply switched from using coal to using gas as its primary fuel. Also, he testifies that Gila River was purchased in anticipation of a reduction in coal capacity as SGS[4] yet because of issues related to the co-owners of SGS 1 wanting to continue ownership in the plant, TEP is in the process of acquiring the remaining 195 MW of SGS 1. Thus, at a time of declining peak demand this 413MW acquisition is actually only replacing the scheduled retirement of 170MW of capacity of San Juan Unit 2. Finally, facts have changed since Mr. Hutchens put in his testimony at the beginning of the case, TEP will not reduce its coal capacity down from 1,551 MW at the end of 2011 to 1030 MW at the end of 2015 as he shows in his testimony but rather only down to 1,395 MW since the Company has moved to acquire the remaining portion of Springerville Unit 1 and San Juan 2 is not scheduled to retire until the end of 2017. It should be noted that none of this is without costs as the Company seeks full cost recovery for Gila River, the stranded assets at Sundt, the stranded assets at San Juan and for full cost recovery for acquisition of all of Springerville Unit 1.

[4] In December 2014 and January 2015, TEP purchased leased interests in SGS Unit 1 totaling 35.4% for an aggregate purchase price of $66 million. These purchases brought TEP's total ownership interest in the unit to 49.5%. Prior to January 1, 2015, TEP leased 100% of SGS Unit 1, received 100% of its 387 MW capacity and owned an equity interest in one of the leases covering a 14% share of the unit.

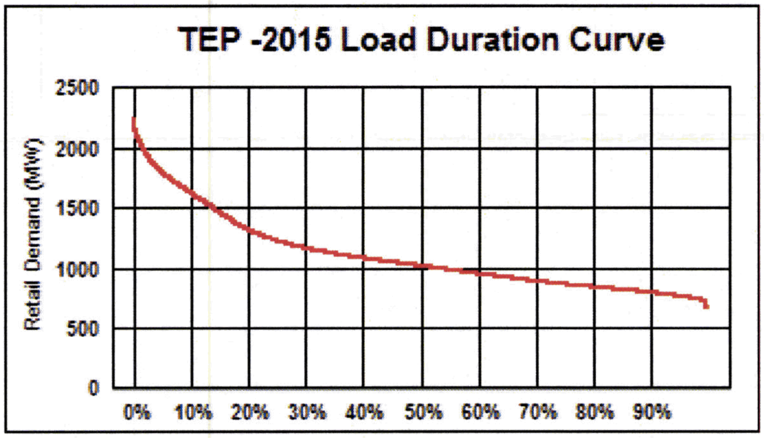
I have prepared the graphs below to illustrate my points[5]. The first graph illustrates the investment made by the Company in its system over the last ten years while the second graph represents the Company's annual sales on a rolling twelve month basis (a rolling 12 month calculation is used to determine trends with each point being one year of data with the next data point adding one month of data and subtracting the oldest month from the calculation). This information was taken supplied from in responses to RUCO 8.06 (Exhibit FWR-2)



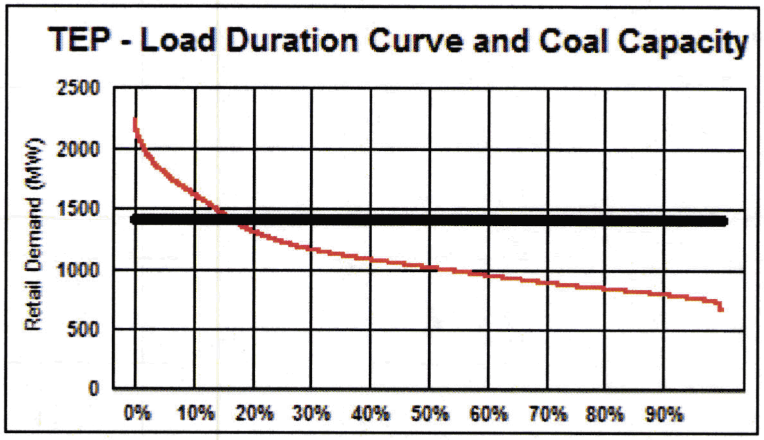


5 TEP Gross Plant in service from TEP FERC Form 1, 2006-2015 inclusive, page 207, TEP retail sales from responses to RUCO 8.06.

As can be seen these two graphs are trending in the opposite directions. I think we should also be cognizant of two other graphs that illustrate TEP's system. The first is a load duration curve which is developed by taking the peak demand in each hour of the year and ranking it from highest to lowest. This graph was developed from data supplied in response to RUCO 8.05 (Exhibit-FWR-3). This is a curve that is used in generation planning and integrated resource planning ("IRP") and is useful when comparing capacity resource options to the load being experienced by the Company. The X axis is the % of hours in the year. As shown below TEP's load is 1,000 MW or less for 50% of all hours in the year.



The next graph is the load duration curve again but the total amount of coal capacity under the Company's operational control for the test year is also shown (Coal capacity data taken from response to Noble 3.6). This curve is useful to compare the amount of base load capacity the Company has versus the need of its retail customers. As shown on the graph below, TEP has a considerable amount of excess coal capacity for a large percentage of time. In fact, TEP coal generation resources exceed its retail load 83% of the time in 2015.



I present these graphs as contextual background to the discussion and adjustments that follow. The Company is asking for a large amount of outstanding issues to be addressed in this case and the cost of them is large. Gila River Unit 3 is being placed in rate base. The Company wants to recover the increased cost for Springerville Unit 1 in the fuel adjustment clause. The Company seeks full cost recovery of the stranded assets related to the Sundt Coal Handling facilities and the pending retirement of San Juan Unit 2. The Company seeks to shorten the service life of San Juan Unit 1 because of problems that may or may not occur almost a decade from now. If these factors were not enough there is the issue of increased rate base to recover the cost of the Company's penchant for new

investments while at the same time load continues a steady ten year old decline.

I propose a series of adjustments to the Company's presentation. The first addresses the capacity acquisition issue. When the Company has excess capacity, it sells it in the wholesale market to recover some of the costs for supporting that capacity. This is done under FERC approved wholesale power contracts. The Company's presentation removes some of the sales unjustly and I propose an adjustment which is more reflective of conditions that occurred in the test year and appear likely to reoccur in the year following when rates are reset, 2017.

My second adjustment is to depreciation. Here I propose two adjustments. The first is to reject the shortening of the service life for San Juan Unit 1. The Company has no firm basis to make this adjustment and given the rate impact, an almost $13 increase in depreciation expense, and the fact that the Company is asking ratepayers to pay for so many other things in this case, I believe the Company's proposed shortening of the service life is premature.

My third adjustment relates to the recovery of post-test year plant. Based on past precedent in this State, post-test year plant might be allowed for recovery in rates when the plant is necessary for the provision of services

and reflects appropriate, efficient, effective, and timely decision-making. As will be discussed in more detail below this Company has a history of being overly optimistic in its load projections and has been asked to review this by Commission Staff. Moreover, when the Company is asked about basic information about its residential customers, which constitute 90% of its customer base, it claims to have little knowledge. Yet, with its propensity for spending, the Company continues to build projects for forecasted load growth that has yet to materialize. I don't believe that the Company has shown that its decisions reflect appropriate, efficient, effective, and timely decision-making and as such, propose to remove post-test year plant for ratemaking purposes.

My fourth adjustment relates to the third, and that is the Company's proposed adjustment for residential test year sales for weather normalization. As noted above the Company claims it has little knowledge about its customers (making no attempt to track the number of vacant homes or the number of seasonal customers) - this brings into question the accuracy of attributing any sales variation to weather as opposed to economic conditions. I propose to only allow half of the proposed weather normalized sales variation for residential customers to be allowed in rates.

My fifth and final adjustment relates to the UNS headquarters building. TEP's parent corporation, UNS, conceived and built this building in the

downtown location. The downtown location was critical because UNS was trying to gain investment tax credits which would have garnered the parent Company considerably financial benefit. When, through the course of events, the tax credits became unavailable after construction of the new building was complete and the employees were about to move into the building, ownership was transferred from the non-regulated entity, UNS, to the regulated entity, TEP, which happened to be filing for a rate case shortly thereafter. Effectively, the parent is attempting to shift the cost burden and risk associated with it from its shareholders to TEPs ratepayers. When UNS was allowed to form a holding Company back in 1997 there was a provision in the Commission's decision approving the holding company as a safeguard to ensure that the formation of the Holding Company structure would not result in adverse consequences to TEP. That provision was that the parent company would charge the lower of embedded costs or the prevailing market rent for any exchange of goods between the parent company and the affiliate. Since the market rent in Tucson is considerably less than the embedded cost of the building, for ratemaking purposes, I propose to reflect this provision of the holding company order into the rate setting process. This would be effectuated by removing the building from TEP's rate base, removing the associated expenses and imputing a market based rent.

JURISDICTIONAL ALLOCATION

Q. COULD YOU PLEASE DISCUSS THE ISSUE OF JURISDICTIONAL ALLOCATIONS?

A. Yes, some aspects of the Company's operations must be removed from the ratemaking process as they are not under the Commission's jurisdictional control for rate setting. The clearest example of this is the issue of transmission where the Company's transmission assets are not under Commission control but rather have been transferred and TEP purchases transmission under an open access transmission tariff. Thus, all transmission assets and expenses are removed from TEP's income statement and rate base for ratemaking purposes. A similar issue comes up with generation which is sometimes sold in the wholesale market. For sales that are short term in nature, less than a year, the revenues and fuel costs are credited to the fuel adjustment mechanism. Long term wholesale sales, contracts over a year in length, are sold at rates approved by the Federal Energy Regulatory Commission. In the Company's presentation it adjusts the income statement and rate base calculations so that the plant associated with these transactions are not recovered within jurisdictional base rates (Dukes direct at 51).

Q. HAVE YOU REVIEWED THE COMPANY'S CALCULATION RELATING TO THIS ADJUSTMENT?

A. Yes and I believe it needs some refinement. Staff asked a discovery question seeking the work papers and supporting documents used to derive the jurisdictional allocations used for each pro-forma adjustment. This was supplied in a confidential spreadsheet, STF3.3JurisdictionalAllocation-Confidential.xlsx. The tab used to allocate the demand related aspects of this issue is attached as Exhibit FWR-4 and shows both retail and wholesale demands for 2015. For wholesale demands, the information is also broken out by contract. To develop their pro-forma adjustment the Company removed 200 MW out of the 296 MW of FERC jurisdictional contracts in order to develop its jurisdictional allocator (See column (h)). No explanation in the discovery response, the spreadsheet provided or the direct testimony of the Company addresses this removal.

Q. DO YOU BELIEVE THE REMOVAL OF THESE TWO CONTRCTS IS REASONABLE?

A. No. One contract for 100 MW is titled Shell. On TEP's FERC Form 1 this contract is listed as being with Shell Energy North America (US) LLP (see Exhibit FWR-5). In response to a discovery question in this case TEP states that this contract was put into place after the acquisition of Gila River Unit 3 and the contract expires on December 31, 2017 (See Exhibit FWR-6). As new rates are scheduled to go into effect on January 1, 2017 it is

unreasonable to take this contract out. The second contract that was removed before calculating the jurisdictional allocator was titled SRP which on TEP's FERC Form 1 this contract is listed as being with the Salt River Project Agricultural Improvement and Power District. A review of TEP's 2014 IRP shows that the SRP project was part of its long term wholesale power supply obligations but that the contract terminated sometime in 2016 (See Exhibit FWR-7). While this would indicate this could be the basis for a proper pro-forma adjustment, a review of TEP's 2016 IRP shows that the Company has entered into a new wholesale power supply contract with the Navopache Electric Cooperative for 44 MW of capacity beginning in 2017. I would also note that the existing contract with the TRICO electric cooperative, which was entered into place after the acquisition of Gila River Unit 3, is scheduled to increase from 50 MW to 85 MW in 2018.

Q. GIVEN THIS INFORMATION WHAT DO YOU RECOMMEND FOR RATE SETTING PURPOSES?

A. Given that the Company has provided no explanation as to why it removed these two contracts, the fact that one of them will continue for at least a year after when new rates are set, that at least one new wholesale contract has been entered into after the end of the test year, that the Company has a history of marketing capacity acquisitions in the wholesale market when they are needed for retail customers, and the fact that retail load has exhibited decline and therefore makes more capacity available for the

wholesale market, I believe that the Company has not shown its adjustment to be reasonable and should therefore be rejected.

I should also note that TEP is requesting that the operational costs of a portion of Springerville Unit 1 be recovered through the PPFAC (Grant Direct at 24). It is important for retail customers that the proper jurisdictional allocation of costs should also apply to the Company's requested recovery of any costs associated with generation through the PPFAC.

DEPRECIATION

Q. PLEASE DISCUSS YOUR ADJUSTMENTS TO DEPRECIATION EXPENSE?

A. As I noted in the introduction to my testimony, I propose two adjustments. The first relates to the service life of San Juan Unit 1 which the Company is proposing a change to the retirement date from 2036 to 2027 based on the feasibility of future coal supply agreement extensions (Sheehan Direct at 26:1-22). As Mr. Sheehan explains the current coal supply contract is scheduled to end by 2022 and any extension to the contract must be renegotiated by 2019 (Ibid). Without given many specifics Mr. Sheehan states there are numerous factors impacting the future of the coal supply and he recommends that the Commission only expect a five year contract extension of the existing agreement.

Q. PLEASE COMMENT.

A. Mr. Sheehan provides little in the way of facts to his proposal. As he notes numerous factors could act to shorten the life of the existing mine and there are numerous other factors that could act to lengthen the life. One most notable is that San Juan Unit 2 was scheduled to cease operations in 2033 (Sheehan Direct at 23) and is now being retired at the end of 2017. All else being equal then some coal mine capacity that was expected to be used for supplying San Juan Unit 2 could now be used to supply San Juan Unit 1. Thus, by using existing resources the mine could supply San Juan 1 for a number of years beyond 2027. Given the facts that nothing is known for certain, I recommend that the current service be maintained.

Q. COULD YOU PLEASE DISCUSS YOUR SECOND ADJUSTMENT TO DEPRECIATION?

A. Yes. The Company is in the process of acquiring all interest in Springerville Unit 1 which will change it from a minor lease owner to actual owner of the unit. As the Company already owns Unit 2, this 793 MW of capacity is a large portion of the Company's generation portfolio. In addition, as these are newer units, they do not suffer some of the same environmental issues impacting the other coal stations in the Company's fleet. Finally, since the Company is acquiring more of this station it appears that this will be the Company's flagship coal generating station on a going forward basis. The service lives of this station, however, do not reflect this outlook. The

expected retirement date Unit 1 is 2045 and the service life for Unit 2 is expected to be 2050. The leasehold improvements at Unit 2 are set to last only until 2024. Given that this is TEP's best unit and it will soon own all of Units 1 and 2, depreciation rates should reflect the Company's long term outlook for the plant and I propose an expected retirement date for Units 1, Unit 2 and all common equipment at 2050.

Q. COULD YOU PLEASE ADDRESS THE ISSUE OF EXCESS DEPRECIATION RESERVE?

A. Yes, there was a provision from the Settlement in the last TEP rate case that any excess depreciation reserve in production plant be used to write off stranded assets due to early retirements and any remaining excess be returned to ratepayers over 15 years[6]. In this case the Company used the excess reserve to write of the Sundt coal handling facilities and the remaining assets of San Juan 2. The Company did this calculation based on 2014 plant balances. However, since rates are going to be reset on January 1, 2017, the Company's calculations does not recognize that both assets continue to accrue depreciation expense which is credited to the depreciation reserve. All else being equal therefore, the Company's presentation removes too much excess deprecation reserve than is necessary to write off these assets. I calculate the amount in question to be approximately $20 million. While the coal handling facilities at Sundt are

[6] Docket No. E-01933A-12-029, Settlement Agreement, Section 20.3.

no longer used a calculation could be done but for San Juan 2, because the plat will be operating for a full three years after the Company performed its calculation there will still be additions and retirement at the plant, the correct calculation will not be able to be done until after 2017. Said another way, it is only after the San Juan 2 Unit is fully retired will the true effect that the write off will have on the excess depreciation reserve. As such, if any excess depreciation reserve is available after all depreciation rates are set in this case, I would recommend that it be revisited in the next rate proceeding and not passed back to ratepayers over the 15 years as contemplated in the Settlement from the last rate case.

POST TEST YEAR PLANT ADDITIONS

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S REQUEST FOR POST TEST YEAR PLANT ADDITIONS?

A. Yes. TEP has adjusted its rate base to include approximately $51.8 million of plant additions that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2015 (Dukes Direct at 43). The Company has also adjusted its rate base to include approximately $20.8 million of plant additions for renewables that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2016 (Dukes Direct at 44). This adjustment extends out an additional 12 months beyond the non-renewable post-test-year cut-off (Ibid). This allows for the reflection of these renewable asset investments approved through the REST

application process to be recovered through base rates as opposed to being recovered through the REST tracker (Ibid).

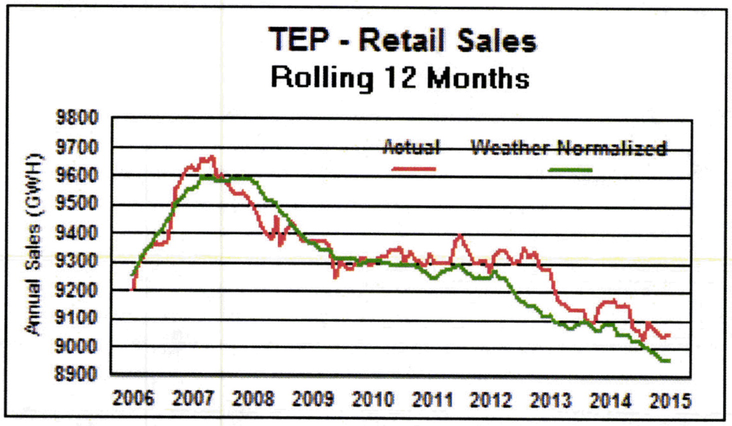
Mr. Dukes argues that these projects will be benefiting customers by the time new rates are effective (Dukes Direct at 43 and again at 44). Mr. Dukes goes on to state that by allowing rate recovery in this rate case will more closely align cost recovery to the Company with the benefits that are currently being provided to existing customers (Dukes Direct at 43). Mr. Dukes also states that rate recovery in this rate case also lowers the cost to customers by limiting the amount of Allowance For Funds Used During Construction ("AFUDC") charged to the assets, thereby reducing the future depreciation and carrying costs associated with this plant (Ibid). Mr. Dukes states that the Company's request is consistent with the Commission's past orders with respect to post test year plant additions as well as the rate treatment allowed it in the last rate case (Dukes Direct at 43 and at 44). Finally, Mr. Dukes concludes that the timely recovery of costs incurred to maintain a safe, reliable electric system is necessary to mitigate larger rate impacts that result from the use of historic test years combined with little to no increase in sales (Dukes Direct at 43).

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S REQUEST?

A. Yes. I would like to start with Mr. Duke's final argument. I think what he means is that it is cheaper to give them the money now while sales are

relatively high because if they have to wait until the next rate case sales will be lower so the resultant percentage increase in rates necessary to reflect them in rate base will be higher. Of course that is really the issue here because one of the caveats that the Commission has used in allowing post test year plant additions is that the utility must show the plant is necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making.

When the utility's sales and peak demand are declining due to the effect of energy efficiency, the growth of distributed generation and persistent weak economic conditions, one must question why the utility continues to plan for and add additional plant. Again, we should keep in mind the trend line for the Company's retail sales.



In this current retail sales environment, if increased safety and reliability is the goal as Mr. Dukes states then one may not need to put in new

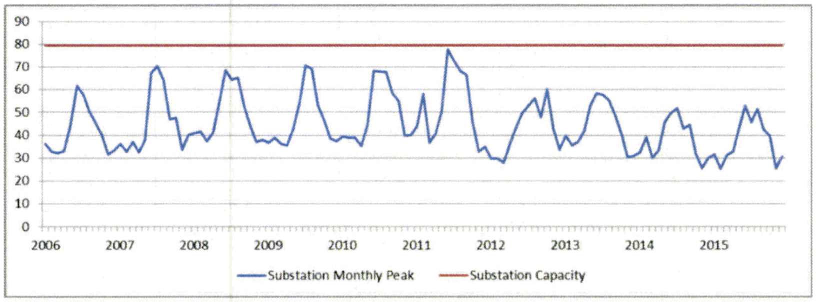
equipment. Rather just wait as the existing equipment becomes unloaded due to the declining sales which thereby cause increased reliability. As I mentioned in my introduction this Company was asked by the Staff of the Commission to reexamine its load forecasting process because it appeared to be somewhat optimistic. This advice hasn't taken root as the Company's core level of investment in transmission and distribution is on par with historic levels (See Exhibit to Grant Direct, KCG-1) and the Company's 2016 IRP load forecasting section heavily relied on the anticipated addition of the Rosemont copper mine, whose owners announced indefinite delay in the project the day the IRP was filed[7].

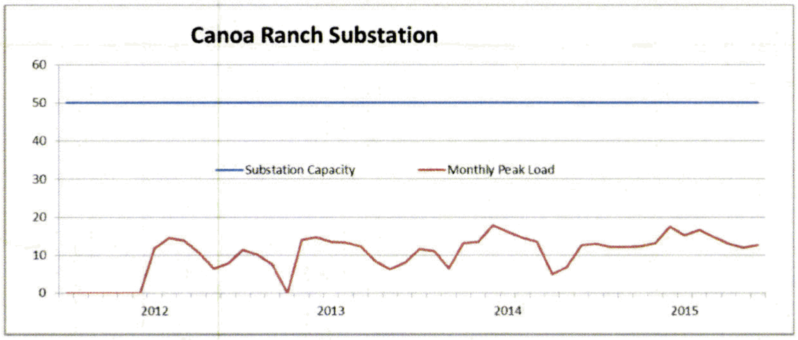
The consequences of building too much plant is telling. In TEP's last rate case, when asked to review their capital spending, I raised questions about the wisdom of their building program. One of these projects I addressed was the new Canoa Ranch Substation. The Canoa Ranch 138kV substation was a recently completed in the southwest portion of the Company's service territory. The substation is essentially on the edge of the developed area of the service territory; if any growth is to occur, it will be from future subdivisions locating in the vicinity. The substation was initially justified by the Company in 2006 to relieve load on other nearby substations, which were being overloaded due to growth in the area (See

[7] http://www.tucsonweekly.com/TheRange/archives/2016/03/01/rosemont-mine-put-on-hold-by-hudbay-minerals

Planning memorandum attached as Exhibit FWR-8. In the planning memorandum citing the need for the new substation it was also noted that its location was close to one of the areas experiencing major load growth (Ibid). Canoa Ranch came into service in 2011 at a cost of $9.8 million and has one 50 MVA transformer, but was designed so that it could accommodate a second 50 MVA transformer in the future (Ibid). At the time, the substation was justified: the substation capacity in the area was 73.5 MVA and the load in the area was 72.2 MVA (Ibid). Thus, the existing capacity was being almost fully utilized. Through discovery in this case I was able to obtain the actual demands on the Canoa Ranch substation and the substations it was built to relieve. The graphs below show the demand on the old substations as well as the new. As can be seen, while the new substation did relieve load on the existing substations, about 20 MW, that's all it did. No new load growth has occurred on either the new or old substation since. To me this vindicates Commission Staff's recommendation that the utility examine its forecasting operations at the core level.

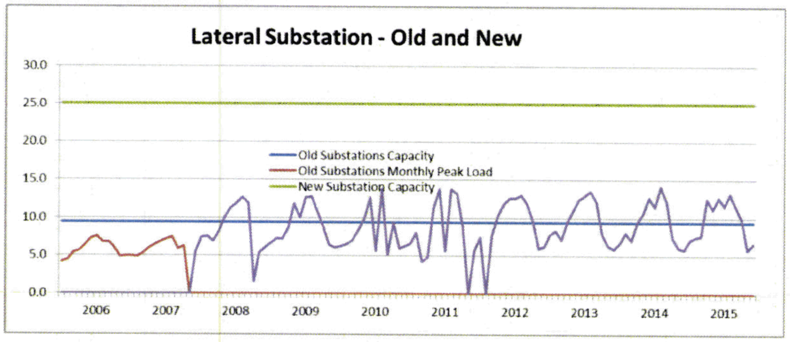
Canoa Ranch Area Substation Demand - Old Substation Load vs. New Substation Load



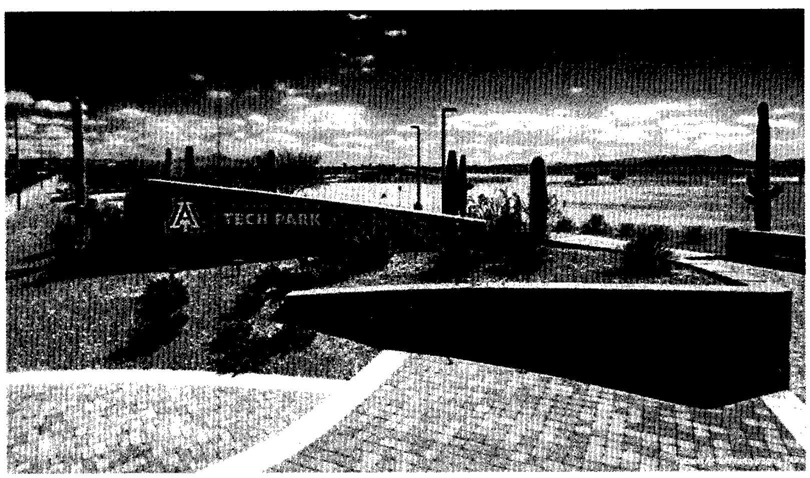


A second example is project D06FM04 "Lateral 7 ½ Substation Improvements". This project involved the retirement of two overloaded smaller substation transformers with one new transformer. The old transformers had a total rated capacity of 9.4 MVA and the new transformer has a capacity of 25 MVA. In the project justification memorandum, a 25 MVA transformer was recommended because the area was projected to get two large subdivisions. The project's final cost was $1.7 million. The project justification memorandum is attached as Exhibit__FWR-9. The graph below depicts the monthly peak demand at the substation together with the capacity rating of the old and new transformers. Like Canoa Ranch, the expected load for this substation never materialized.

Lateral Substation – Load vs. Transformer Capacity



Based on my review of upcoming projects in the transmission and distribution system, I am fearful that this build out of the system in hopeful anticipation for historic load growth is continuing. One case in point is the planned Kino Substation. The Kino area in southern Tucson is serviced by five substations, 21st St, 35th St, Pueblo Gardens, Drexel, and Fair St. Recent and TEP forecasts that load growth and a large planned community called "The Bridges" has created an increase in load for this area that will continue as The Bridges gets built out. The Bridges is a 350-acre master-planned mixed-use development consisting of 1,000,000 square feet of commercial/retail/office land uses a 350 room hotel, up to 1,084 residential units consisting of single family attached homes and a research park associated with the University of Arizona. The plan for the Bridges was originally proposed in 2007[8]. The pictures below show and aerial view and a street view of the Bridges as it exists today. As one can easily, see there has been little meaningful development at the Bridges in the last 10 years



Q. PLEASE DISCUSS WHEN IT IS APPROPRIATE TO INCLUDE POST TEST YEAR PLANT IN RATES.

A. I believe the best description of the Commission's guiding principles is that used in Decision No. 71410. There the Commission explained that its rules

[8] https://www.tucsonaz.gov/files/pdsd/plans/Bridges_PAD_Complete.pdf

require the end of the test year, which is the one-year historical period used in determining ratebase, operating income and rate of return, to be the most recent practical date available prior to the filing (Ibid at page 19). The Commission noted that a utility has the freedom to choose a test year that includes all major rate base and operating income items needed to support its rate application, and to include pro forma adjustments to its chosen test year (Ibid at page 20). The Commission further noted that matching is a fundamental principle of accounting and ratemaking, and the absence of matching distorts the meaning of, and reduces the usefulness of, operating income and rate of return for measuring the fairness and reasonableness of rates (Ibid).

In that case, the Commission adopted several Staff adjustments in the case to remove proposed post-test year plant additions from the rate setting process. In its direct testimony in the case, Staff explained that the matching principle is the reason that the Commission has allowed inclusion of post-test year plant in rate base only in special and unusual situations, which could be summarized as follow:

1) when the magnitude of the investment relative to the utility's total investment is such that not including the post-test year plant in the cost of service would jeopardize the utility's financial health;
2) where the cost of the post-test year plant is significant and substantial;

3) where the net impact on revenue and expenses for the post test year plant is known and insignificant (or is revenue-neutral); and

4) where the post-test year plant is prudent and necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making (Ibid).

I believe it is this last test where TEP fails in its presentation. At a time when sales and peak are declining, a request for post test year plant recovery in rates requires a detailed presentation that the large and continuous build out of infrastructure reflects appropriate, efficient, effective, and timely decision-making. Absent such a showing on the Company's part, I recommend that no post test year plant additions be reflected in rates.

WEATHER NORMALIZATION

Q. PLEASE DISCUSS THE ISSUE OF WEATHER NORMALIZATION.

A. As explained by Company witness Craig Jones, weather normalization is a standard adjustment commonly performed in rate cases (Jones Direct at 66). It is performed to provide a best estimate of test year sales, revenues, and costs as they would have been under normal weather conditions (Ibid). Energy consumption for some of TEP's customer classes are weather sensitive (Ibid). For instance, a significant portion of energy usage in the summer comes from air conditioning load (Ibid). Some summers, however, are warmer than normal and result in the Company selling more power and receiving more revenues than in a "normal" year (Ibid). The reverse of this occurs when cooler than normal summer weather is experienced (Ibid). The purpose of weather normalization is to "average" out these differences, so one can get a better sense as to what the Company is likely to receive in revenues during a year with normal weather (Ibid). Mr. Jones then goes on to describe the Company's new method for isolating the effects of weather and he believes that the Company's new method is superior in its accuracy. (Jones Direct at 68-70).

Q. HAVE YOU REVIEWED THE COMPANY'S NEW METHOD AND UNDERLYING ASSUMPTIONS?

A. Yes to the extent I could. The Company uses ten year average of weather in its model whereas some other utilities use 20 or 30 year averages in order to adequately smooth out year to year variations in weather. The Company refused to run their model on any other term other than ten years (see responses to RUCO 7.3 and 7.4 attached as Exhibit__FWR-10) so it is impossible to test the robustness or true accuracy of the model. More troubling is the fact that the Company does not track the number of vacant homes in its service territory or the number of seasonal customers (See response to RUCO 7.11 attached as Exhibit__FWR-11). Both of these are vital in determining normal energy use. Moreover, while the Company states that use per customer has been steadily declining, (See Dukes direct at 14), when asked to break out the causes for this decline the Company was able to accurately break out the effects of weather and energy efficiency but for any other variation not predicted by its model it labeled the variation "Other Change" (See response to RUCO 8.04 attached as Exhibit__FWR-12). This category "Other Change" could be because of modeling error, estimation error in the case of the impact of energy efficiency or economic conditions such as an increase/decrease in the number of homes that are vacant or an increase/decrease in the amount of seasonal customers. The fact that this category moves up or down seemingly in a random pattern but at a magnitude that can be as large as the weather variation indicate that the Company might be well served to revisit its usage modeling and include such basic parameters as short term economic conditions (i.e. variations in the number of seasonal customers or changes in the number of vacant homes). As it is, I cannot verify that the Company's adjustment for weather accurately measures the change due to weather or for some "Other Change". As such, I recommend that only ½ of the Company's proposed adjustment for weather for residential customers be allowed to be reflected in rates and these results in a decrease in the revenue requirement of $835,322.

NEW HEADQUARTERS BUILDING

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENT IN A NEW HEADQUARTERS BUILDING.

A. In the current rate case, TEP continues to reflect the cost of the UNS headquarters building in its rate base. At June 30, 2015, the total capitalized portion of the building was $82,583,748 of which $5,620,447 was computer and office equipment. See response to RUCO 7.20 attached as Exhibit-FWR-13).

Q. WAS THE COST AND USE OF THE New HEADQUARTERS BUILDING AN ISSUE IN THE COMPANY'S LAST CASE?

A. Yes. Staff Witness Ralph Smith testified that the cost of the new building was a 77% increase in TEP's corporate facility cost per employee (Docket No. E-01933A-12-0291, Smith Direct at 24:20-23). Mr. Smith then elaborated on Staff's concerns (Ibid at 25).

> Beyond the sheer magnitude of the per employee facilities cost increase, Staff's other concerns about the cost of the new building is that the new building includes substantial amounts of office space that are not currently being used, that the new building includes approximately $2.1 million cost for retail space that is not currently being used, that the building includes a cost of approximately $16 million for underground garage/parking,[6] and that TEP has not adequately substantiated that its proposed charging of new building costs to ratepayers is fair and reasonable.

To address these concerns Staff proposed removing approximately 10% of the building's cost from rate base.

Q. PLEASE PROVIDE SOME BACKGROUND ON WHY A NEW HEADQUARTERS BUILDING WAS PLANNED?

A. The Company began considering consolidating office space in mid-2007 (Exhibit__FWR-14). At the August 2008 Meeting of the UNS Energy

Corporation ("UNS"), formally known as UniSource Energy Corporation, the UNS Board of Directors was given a presentation regarding the status of existing corporate facilities and the options for housing corporate employees in the future (Exhibit__FWR-15). Some of the main reasons cited for the consolidation were to bring all corporate functions under one roof and to move corporate-function employees downtown to an urban environment (Ibid). UNS saw the new headquarters as a means to show it was a leader in downtown redevelopment and to improve their corporate image by bringing 200 jobs to the downtown area in a brand new building with 100,000 square feet of rentable space (Ibid).

Q. DID UNS EXAMINE MANY OPTIONS IN DECIDING WHERE TO LOCATE ITS NEW HEADQUARTERS BUILDING?

A. Yes, UNS examined 23 different locations with varying land and building sizes and different cost assumptions, such as on-site parking. No fewer than eight potential sites were rejected because the site did not make a good location for a Corporate Office complex. Five other sites were unfavorably rated as they were located outside of the downtown area. Based on a review of all material provided, it is clear that UNS was focused on a downtown site for its new corporate headquarters.

Q. ARE YOU AWARE OF ANY OTHER FACTORS THAT IMPACTED THE CONSTRUCTION OF THE NEW HEADQUARTERS BUILDING?

A. Yes, one of the major factors influencing the ownership and location of the new headquarters building was the potential availability of New Market Tax Credits. New Market Tax Credits are a Federal program to incent investment in low-income communities. The New Market Tax Credit Program was established in 2000. The credit program is incorporated in Section 45D of Internal Revenue Code. The program allows for the receipt of credit against Federal Income taxes for making Qualified Equity Investments (QEI) in qualified community development entities (CDE's). The program was established with the expectation of creating jobs and making material improvement in the lives of residents of low-income communities or populations.

A qualified equity investment is defined as an investment into a Community Development Entity (CDE). The CDE enters into an allocation agreement with the Community Development Financial Institutions Fund (CDFI) who provides allocations of New Market tax credits to CDI's allowing them to attract investments from the private sector to be reinvested in low income communities

The program provides for credits equal to 39% of the investment into the CDI. The credit is provided over a seven years and is equal to 5% of the qualified investment in Years One-Three and 6% of the qualified investment in Years Four-Seven. By use of leveraged finance, UNS expected to invest $8.6 million of its own equity and receive credits to income taxes of $12.3 million (FWR-16 Excerpt from Attachment to RUCO 7.13, October 2010 Presentation). In other words, the new market tax credit would have resulted in a 43% return on the UNS investment in the new headquarters.

Q. WHEN DID THE COMPANY REALIZE THAT IT WOULD NOT BE GETTING THE NEW MARKET TAX CREDIT?

A. In his May 2011 presentation to the Board of Directors Mr. Scott Rathbun addressed UNS's decision to abandon participation in the NMTC program (Exhibit__16 Excerpt from Attachment to Response to 7.13, May 2011 Presentation). According to Mr. Rathbun, the large banks that would invest in NMTC programs like that of the new headquarters would not allow UNS to co-invest with them in the project. Mr. Rathbun also cited the limited availability of NMTCs for a project as large as the new headquarters. Finally Mr. Rathbun also included an explanation that read as follows:

> "...to obtain this level of NMTCs we would need to rent our retail space...to a type of tenant that was viewed as supporting the local residential community. To attract that type of tenant would significantly subsidize the rent and leasehold improvements; the level of subsidy would partially, if not completely, offset the tax benefits to the Company."

It was therefore concluded that, due to the above circumstances, UNS's net tax benefit for receiving NMTCs would fall something short of $5 million instead of the $12.3 million estimated by the Company a year prior.

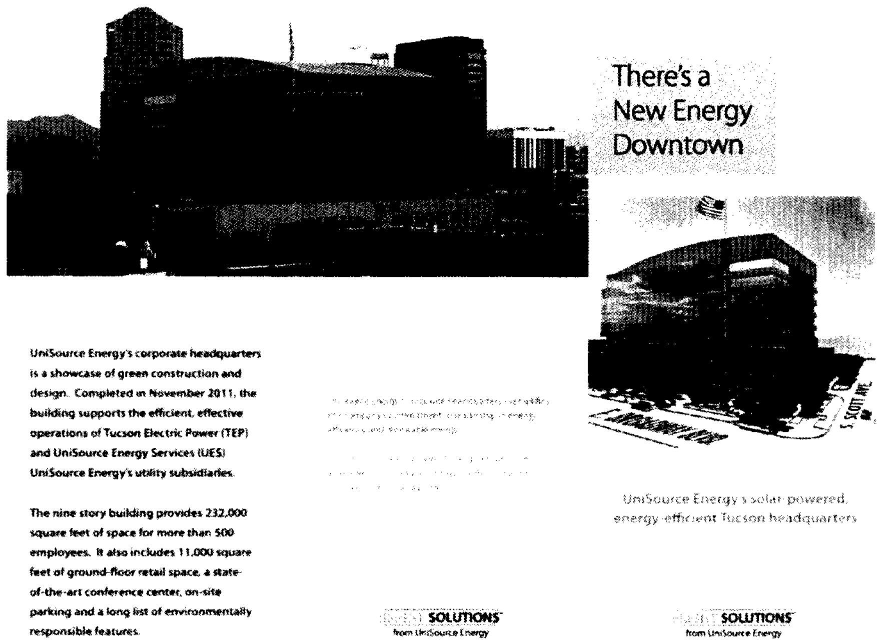
Q. WHEN DID UNS TRANSFER OWNERSHIP OF THE NEW HEADQUARTERS BUILDING TO TEP?

A. November 1, 2011, after construction of the new building was complete and the employees were about to move in (Exhibit__FWR-17).

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPANY'S DECISION MAKING PROCESS?

A. The facts are clear the new headquarters building was conceived as a corporate headquarters for UNS and not for TEP. The original plan and design of the building was just to bring employees with corporate duties together under one roof. That the new building is the headquarters of the UNS Corporation is still the building's main function. Brochures in the lobby of the new building describe the building as "UniSource Energy's solar-powered energy-efficient Tucson headquarters" and declare the corporate headquarters "a showcase of green construction and design" (Exhibit__FWR-18 UNS Headquarters Brochure).

Unredacted Direct Testimony of Frank W. Radigan
Tucson Electric Power Company
Docket No. E-01933A-15-0322 et al.



While UNS may want a downtown address to improve its image and show community leadership that is certainly not a key necessity of a regulated Company such as TEP. Only long after the initial project review did the Company even consider bringing in more employees from the Irvington Road campus. It should be noted that the Irvington Road campus is not empty, the Company has no plans to sell it, and there are still hundreds and hundreds of employees at the Irvington Road facility which the Company describes as an "industrial site". The evidence is clear that the new headquarters building was conceived and designed for UNS first and TEP as an afterthought.

It is also evident that UNS vigorously pursued the project in the hope of receiving a large return on its investment through the use of new market tax credits. UNS bought the land and paid for the construction of the new facility (Exhibit__FWR-19 Excerpts from UNS 10-Ks for 2009 and 2010) in the hope of getting these tax credits. It was only after UNS became aware that it would not get the tax credits was ownership transferred to TEP.

Q. WHAT ARE THE RATEMAKING IMPLICATIONS OF THE NEW HEADQUARTERS BUILDING BEING PRINCIPALLY BUILT FOR CORPORATE PURPOSES?

A. First – if the building is owned by the parent company and rented to the regulated utility-TEP, ratepayers would be responsible for the rent expense which for ratemaking purposes is treated as an operating expense. Whereas, by transferring ownership to the utility, the capital costs associated with the building become a part of TEPs ratebase and the Company's shareholders will earn a return on and a return of those capital costs. Moreover, the losses associated with the Company's inability to rent space become the burden of the ratepayer and not Unisource's shareholder who the building was designed for in the first place. The way the Company is proposing the ratemaking treatment is far more costly to TEP's ratepayers than the rental proposition for a building that was arguably designed and acquired for UniSource's needs – not TEPs.

Second - Docket No. U-1933-97-176[9] was the proceeding whereby Tucson Electric Power Company was allowed to form a Holding Company. In that proceeding, the Company proposed 17 conditions as safeguards to ensure that the formation of the Holding Company structure would not result in adverse consequences to TEP. In approving the petition, the Arizona Corporation Commission imposed several more safeguard conditions and approved those proposed by the Company. One of the original safeguard conditions was as follows:

> The Holding Company, TEP and sister companies will strive to charge the lower of fully allocated cost or market price whenever goods, products or service are sold/provided by the Holding Company or sister companies to TEP and the higher of fully allocated cost or market whenever TEP sells/provides non-tariffed goods, products or services to the Holding Company or sister companies. The Holding Company, TEP and sister companies recognize that determining a market price for all goods, products and services being transferred in and among the Holding Company, TEP and sister companies could be a complex or difficult task for some items. Nonetheless, the Holding Company, TEP and sister companies agree to attempt to determine a market price for any good, product or service being provided by TEP to the Holding Company or sister companies as well as for any good, product or service provided by Holding Company or sister companies to TEP whenever the annual, fully allocated cost for given good, product or service being transferred exceeds $500,000 annually. Furthermore, TEP will retain such market research information (regardless of whether it is ever utilized) until such time as the Utilities Division Staff or its representative have reviewed such information.

The implications of these safeguard conditions are clear: had UNS continued to own the new headquarters building it would not be allowed to

[9] Docket No. U-1993-97-176, In the matter of the Notice of Intent of Tucson Electric Power Company to Organize a Public Company Holding Company and for Related Approvals or Waivers Pursuant to R14-2-1801, ET SEQ., Decision No. 60480 issued November 25, 1997.

charge any more than market rates for rent. If TEP owned the building, however, it would be allowed to charge the higher of embedded cost or market rates. In other words, if the cost of the new building exceeded the market rate, TEP should own the building; if the cost of the new building was less than the market rate, the holding Company became indifferent to who owns the building.

Q. WHAT DO YOU RECOMMEND BE DONE IN THIS PROCEEDING?

A. Given that the new headquarters building was built primarily for purposes of the Holding Company and for ratemaking purposes, it should be assumed to be owned by the Holding Company and TEP should pay no more than the going market rate. As such, all assets related to the land and new headquarters building should be removed from rate base, along with any operation and maintenance expenses or taxes associated with the new headquarters building. Based on the 263,365 square feet of rentable office space in the new building, the difference in cost between UNS' fully allocated cost to serve and the market rate of $20 per square foot equates to a rental rate of approximately $5.3 million per year. Removing the new headquarters from rate base and its associated expenses from the income state results in a reduction in revenue requirement of approximately $7.5 million.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

EXHIBIT
RUCO
8
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322

DIRECT TESTIMONY

OF

FRANK RADIGAN

ON

RATE DESIGN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 24, 2016

TABLE OF CONTENTS

EXHIBITS

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services in electric, gas and water utility industry matters, and specializing in the fields of rates, planning and utility economics. My office address is 235 Lark Street, Albany, New York 12210.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, on June 3, 2016 I submitted testimony on behalf of the Residential Utility Consumer Office ("RUCO") with respect to certain revenue requirement issues in this case. In this testimony I address other aspects of Tucson Electric Power Company's presentation ("TEP" or "the Company") with respect to revenue allocation and rate design. RUCO witness Lon Huber will also be submitting testimony with respect to rate design issues.

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were. I have two exhibits Exhibit_FWR-20 - Select Discovery Questions and Replies Relating to DG, and Exhibit_FWR-21 - RUCO Schedule H which contains schedules H1-H-4 inclusive.

SCOPE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked to review the revenue allocation of the rate increase amongst service classes, the proposed consolidation/elimination of many of the lifeline rate rates and the need for better, clearer and more thorough presentation of cost of service studies in future rate proceedings.

Q. HAVE YOU PREPARED AND EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes, I have prepared one Exhibit, Exhibit_FWR-20 RUCO-Schedule H, which contains 28 pages that summarizes the revenue allocation, rates for all customers and bill impacts for residential customers.

SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. While TEP proposed revenue allocation does follow the general results of the embedded cost of service study, I believe the relative rates of return of the service classes could be better improved if one more closely followed the results of the cost of service study and use the following principles 1) the Lighting Class should be given the largest relative increase followed by the Residential Class with a slightly larger than average increase, 2) the General Service and Large Power Service Classes should get less than average increases, and 3) the Large General Service should get about an average increase.

For rate design, starting with the Residential Service Class, R-01, I kept the Basic Service Charge at $10 per month in accordance with the recommendation of Mr. Huber. For energy charges, I eliminated the fourth block, again according with the recommendation of Mr. Huber, and increased the rates for the first three blocks on an equal percentage basis to recover the remainder of the revenue requirement. For the other Residential Tariff Classes I applied the same methodology of keeping the basic service charge at current levels and apply the rate increase to existing rates.

For Lifeline rates, given the very large rate increase that the Company is proposing I do not support the Company's proposal to reduce the current 27 rate offerings down to 5. While I do not object to the Company's proposal for new customers where they will receive a fixed discount, the proposal for the existing customers is unacceptable from a customer impact point of view. I propose that the Company reconsider its proposal and 1) develop a new one where existing frozen classes remain as is, and 2) for non-frozen classes, redevelop a rate proposal that does not result in undue customer rate impacts.

As to the continued use of serving net metered customers through a rider, I propose that they become their own service class in the future. The Company makes compelling arguments as to how this class of customers is different than others and may be more costly to serve. That said, the Company reports that it does little to track these customers. Since roof top solar continues to grow as a resource, this continue will continue to grow and become more pronounced so setting the proper rates for these customer will become more important going forward. As such, I recommend that the utility start treating these customers as a separate class of customers and gather the appropriate cost and load data to track them for presentation in future cost of service studies. I also recommend that the Company improve its cost of service presentations generally so that parties can better understand the source data.

REVENUE ALLOCATION

Q. COULD YOU PLEASE DISCUSS THE ISSUEOF REVENUE ALLOCATION?

A. Revenue allocation is a two part exercise where the first step is to correct for any imbalances that exist between service classes in providing the utility an adequate rate of return and the second is to allocate the rate increase among service classes. In the first step, the results of the cost of service study are reviewed to determine how each service classification is doing with respect to providing the utility with the earned rate of return. If a service class is providing less than the average, in an ideal world, it should be given a greater than average increase to bring its earned rate of return up to the average. For example, if the utility is earning a 10% overall average rate of return and one particular service class is earning a 7% rate of return while another is earning a 13% rate of return, then the rate designed would give a higher than average increase to the first service class, in the example, and a lower than average increase to the second service class, in the example. Generally, a tolerance band, +/-10% or +/-15% is applied to determine what an acceptable rate of return is. The tolerance band is used to allow for the fact that any cost of service study is a snap shot in time and for inaccuracies in sample data and allocation methodologies. A review of relative rates of return from cost of service to study to cost of service study is also reviewed and used as a tool in determining how to allocate revenues between rate classes.

Q. WHAT HAS THE COMPANY PROPOSED IN THIS CASE?

A. Company witness Craig Jones sponsors the cost of service and revenue allocation in this case. As Mr. Jones summarizes TEP's position in his testimony

> "TEP is proposing the necessary steps to improve its price signals and to transition over time to more appropriate rate design. Thus, our proposal uses: (1) the results of the embedded cost study to provide important guidance for the class allocation of revenues; and (2) the embedded cost study and the marginal cost study to determine the level of specific charges that taken together create just and reasonable rates." (Jones Direct at page 12)

The results of the embedded cost of service study and Mr. Jones proposed revenue allocation of the requested rate increase as taken from Schedule G is shown below.

	ECOS Rate of Return	Relative Rate of Return	TEP Allocation of Base Rate Increase	% Increase	Relative to Total
Residentail	-1.93%	-0.35	$ 65,402,412	15.9%	0.88
General Service	22.40%	4.06	$ 8,019,784	4.3%	0.24
Large General Service	6.47%	1.17	$ 38,006,508	55.5%	3.07
Large Power Service	12.72%	2.30	$ 1,466,326	2.0%	0.11
Lighting	-13.61%	-2.47	$ 1,245,909	37.8%	2.09
Total	5.52%	1.00	$ 109,534,118	18.1%	1.00

Q. COULD YOU PLEASE COMMENT ON TEP'S PROPOSAL?

A. Yes. Generally, TEP proposal does follow the general results of the embedded cost of service study in that it gives lower than average rate increase to the General Service and Large Power Service Classes and an above average increase to the Lighting Class. It also gives a disproportionate increase to the Large General Service Class even though this class is earning an above average rate of return. I believe the relative rates of return of the service classes could be better improved if one more closely followed the results of the cost of service study and use the following principles; 1) the Lighting Class should be given the largest relative increase followed by the Residential Class with a slightly larger than average increase, 2) the General Service and Large Power Service Classes should get less than average increases, and 3) the Large General Service should get about an average increase. My proposed revenue allocation using RUCO recommended rate increase is shown below.

	RUCO Allocation	% Increase	Relative to Total
Residentail	$ 11,780,417	2.9%	1.60
General Service	$ 1,844,489	0.7%	0.39
Large General Service	$ 2,053,817	1.8%	1.03
Large Power Service	$ 733,028	0.5%	0.30
Lighting	$ 140,858	3.0%	1.66
Total	$ 16,542,000	1.8%	1.00

RATE DESIGN

Q. COULD PLEASE DISCUSS YOUR ISSUES WITH RESPECT TO RATE DESIGN?

A. Yes, starting with the Residential Service Class, R-01, I kept the Basic Service Charge at $10 per month in accordance with the recommendation of Mr. Huber. For energy charges, I eliminated the fourth block, again according with the recommendation of Mr. Huber, and increased the rates for the first three blocks on an equal percentage basis to recover the remainder of the revenue requirement. For the other Residential Tariff Classes, I applied the same methodology of keeping the basic service charge at current levels and apply the rate increase to existing rates.

Q. WHAT IS YOUR RECOMMENDED RATE DESIGN FOR THE LIFELINE RATES?

A. As described by Company witness Jones, the Company is proposing major changes to its low income rates which are referred to as Lifeline rates. The Company proposes to change the current rates that give either a fixed discount or discounts from the otherwise applicable rates to a single uniform discount off of each of the residential rates (Jones Direct at 57). The modifications would reduce the 27 existing tariffs down to five different open rate options, one for each of the five existing residential rates, and apply a flat $15.00 per month discount, limited to a reduction of the bill down to zero dollars (Ibid). The Company is also proposing changes to its frozen Lifeline rate options that will reduce them from 22 to five different options (Jones Direct at 58).

Q. WHAT IS THE COMPANY'S REASONING BEHIND THESE CHANGES?

A. As explained by Company Witness Jones, the 27 different variations of Lifeline discounts differ by consumption in any given month and also apply to Bright Community Solar customers, net metering customers and even Super Peak TOU customers (Ibid). He argues then that it has become overly burdensome to train customer service representatives to explain the variations, maintain the multiple tariffs needed to explain the variations and maintain and update the processes in the billing system. He also states that 11 of the 27 different Lifeline rates contain fewer than 20 customers, and two of the rates being maintained have just one customer on them.

Q. WHAT IS THE QUALITATIVE IMPACT OF THE PROPOSED CHANGE?

A. As explained by Company Witness Jones, all existing Lifeline customers on rates "that are not frozen" will stay on the fixed credit version of the Lifeline rate that they are currently on but rate increases will apply so that most typical Lifeline customers will experience a total dollar increase on an annual basis that is in a range similar to the dollar increase for a non-Lifeline residential customer (Jones Direct at 59). Customers on "the old frozen rates" will have the same fixed discount available to them as the open Lifeline rates, but the frozen Lifeline customers will have a lower basic service charge of $12.00 per month since they were receiving substantially larger discounts (Ibid)

Any new customer qualifying for the Lifeline program (or existing Lifeline customer moving to a new location) will become a standard residential customer and pay a non-Lifeline residential rate with a flat $15.00 per month discount applied to the bill, with the discount limited to no more than the actual bill in order to prevent a bill from being below zero (Ibid).

Q. WHAT IS THE QUANTITATIVE IMPACT OF THE COMPANY'S PROPOSAL?

A. The table below is taken from Schedule H which is Schedule H 2-2 which summarizes the rate impact by the individual rate schedules from the Company's proposal. As one can see the quantitative impact of the Company's proposal results in rate impacts that can increase a customer's bill by as much as 50%.

	Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue		Proposed Revenues		Proposed Increase to Test		Proposed Increase to	
Rate Description	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
Lifeline Rate Schedules											
TE4-01	187,990	89,256	(23,299)	175,417	78,529	197,746	78,529	(970)	-0.35%	22,328	8.79%
TE4-21	1,612	1,028	(57)	1,567	1,016	2,372	1,016	748	28.34%	805	31.15%
TE4-70	3,139	1,644	(76)	3,077	1,629	4,143	1,629	989	20.68%	1,066	22.64%
TE5-01	571,226	277,370	(46,143)	547,423	255,030	613,101	255,030	19,535	2.30%	65,678	8.18%
TE5-21	1,242	807	(356)	738	455	1,057	455	(537)	-26.23%	319	26.74%
TE5-70	5,466	2,786	(786)	5,162	2,304	6,226	2,304	278	3.37%	1,064	14.26%
TE6-01	3,730,879	1,828,957	(803,104)	3,203,498	1,553,234	3,690,634	1,553,234	(315,967)	-5.68%	487,137	10.24%
TE6-21	12,269	7,969	(2,560)	10,790	6,887	16,656	6,887	3,306	16.33%	5,866	33.18%
TE6-70	43,687	23,012	(15,364)	34,101	17,235	43,346	17,235	(6,119)	-9.17%	9,245	18.01%
TE6-201A	169,675	102,562	(47,539)	149,713	74,985	210,290	74,985	13,037	4.79%	60,576	26.96%
TE6-201B	2,038	1,298	(571)	1,840	926	3,005	926	595	17.83%	1,165	42.14%
TE8-01	386,096	196,771	(49,567)	329,967	203,333	468,115	203,333	88,582	15.20%	138,148	25.90%
TE8-21	4,771	3,238	613	4,722	3,898	9,061	3,898	4,951	61.83%	4,338	50.32%
TE8-70	9,942	5,317	(670)	8,887	5,702	14,437	5,702	4,880	31.98%	5,550	38.04%
TE8-201A	7,659	4,895	(2,503)	6,028	4,023	10,975	4,023	2,444	19.47%	4,947	49.22%
TE6-01BC	9,626	4,699	(2,038)	8,290	3,997	9,566	3,997	(762)	-5.32%	1,276	10.39%
TE-R-01LL	2,674,986	1,311,018	862,874	3,316,275	1,532,603	4,281,775	1,532,603	1,828,373	45.87%	965,500	19.91%
TE-R01LB	8,347	4,190	1,367	9,438	4,466	11,808	4,466	3,738	29.81%	2,370	17.05%
TE-201AL	74,180	40,970	31,728	102,638	44,240	140,855	44,240	69,945	60.74%	38,217	26.02%
TE-201BL	1,323	877	1,975	2,746	1,429	4,753	1,429	3,982	180.98%	2,007	48.06%
TE-R80LL	35,808	19,187	5,372	40,408	19,959	60,378	19,959	25,342	46.08%	19,970	33.08%
TE-R8LL	707	334	(21)	674	346	926	346	231	22.15%	252	24.66%

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S PROPOSAL?

A. Given the very large rate increase that the Company is proposing, I do not support the Company's proposal as presented. While I do not object to the Company's proposal for new customers, where they will receive a fixed discount, the proposal for the existing customers is unacceptable from a customer impact point of view. Moreover, the Company's proposal is not supported by the facts as presented. Many of these existing rates receive either a fixed discount in dollars or a discount as a percentage. As these are existing in the current billing program there is little administration to them. In addition, many of these rates are frozen, 22 of them, and don't even apply to new customers. The fact that the Company states that 11 of the 27 rate schedules have less than 20 customers on them so the question must be asked as to why even bother going to so much effort for so few. Also, the Company states it is making its proposal to reduce its administrative workload but I can find no evidence that it has proposed a pro-forma adjustment to share that savings with customers. In sum therefore, I propose that the Company reconsider its proposal and develop a new one where existing frozen classes remain as is, and for non-frozen classes redevelop a rate proposal that does not result in undue customer rate impacts.

Q. PLEASE DISCUSS YOUR PROPOSAL FOR THE NON-RESIDENTIAL RATE CLASSES.

A. For non-demand metered rates classes, General Service and Lighting, I kept the basic service charge at current rates and then increased the per unit charges on an equal percentage basis to recover the proposed rate increase. Keeping the basic service charge at current rates for the General Service class is consistent with Mr. Huber's reasoning for the Residential Class. The basic service charge for the Lighting Class is zero and the Company proposed to keep it at zero and I agree.

For the demand metered classes, Large General Service and Large Power Services, because of the small rate increases being recommended - both because of RUCO's proposed rate increase and the recommended revenue allocation - I kept the energy rates unchanged and changed the demand charge to recover the remaining revenue share. In both cases this resulted in a decrease in the existing demand charge because the Company is proposing to move a substantial amount of sales from the unmetered General Service class to the Large General Service Class and eliminate the non-TOU Large Power Service Class. The TOU Large Power Service Class has a higher energy charge and basic service charge than the non-TOU which resulted in an increase in Class revenues that offset the need for a rate increase in base rate.

FUTURE COST OF SERVICE STUDIES

Q. COULD YOU PLEASE DISCUSS THE ISSUE OF FUTURE COST OF SERVICE STUDIES?

A. As explained by Company Witness Dukes the Company proposes to create a new Rider R-1, post June 1, 2015, where partial requirement customers qualifying for the new Rider R-15 to choose from either a non-TOU or TOU three-part rate tariffs which includes a demand charge for their service requirement (Dukes direct at 8 and 27). As Mr. Dukes explains TEP is making these proposals to better align rate design with cost-causation and to reduce inter-class inequities (Dukes Direct at 7).

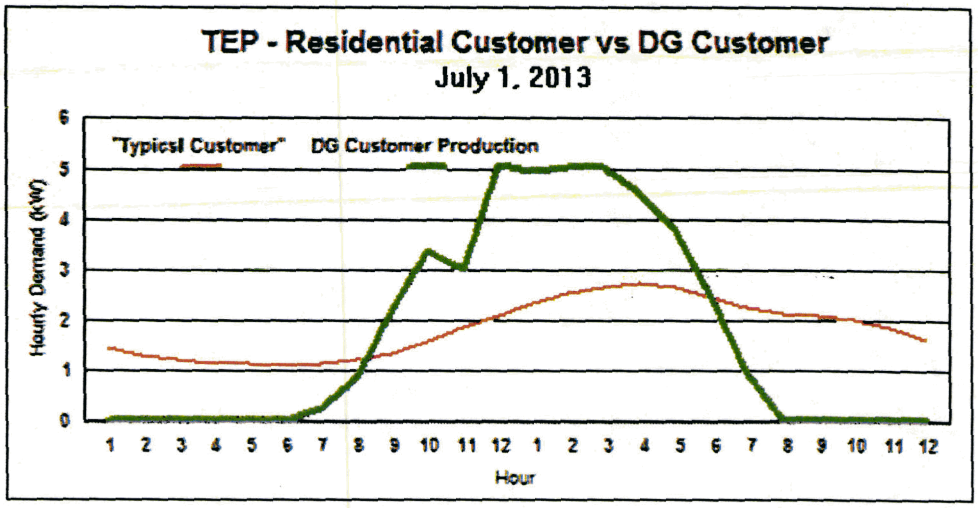
In addition to the rate design changes being proposed Company Witness Jones states that traditional rate classes are no longer homogeneous and the availability of self-generation (particularly solar distributed generation) has created a second class of customers within the typical residential service class (Jones Direct at 15). Mr. Jones further states that partial requirements customers require various utility services, including standby service, supplemental service, delivery service for both in-bound and out-bound power flow, regulation services, power factor correction and balancing (Ibid). For distribution services, the cost of serving these partial requirements customers is typically the same or higher than it was when the customer was a full service customer because the DG customer may require additional investments in the distribution system to provide frequency control and power factor correction (Ibid).

Q. PLEASE COMMENT.

A. My understanding is that there are currently over 11,000 of these customers whose distributed generation supplies over 170 MW of power. The number of new applicants for roof-top solar has been generally consistent at 300 applications per month. Thus, the issue of DG and its impact of cost and cost inequities between different types of customers will continue to grow and perhaps become more pronounced. If a cost inequity does exist then the partial requirements customers are being subsidized by other customers and the amount of cross subsidization will only grow over time. As such, both partial requirements customers and full service customers should know the true cost to serve a partial requirements customer, so the appropriate rate and rate structure can be designed to fairly serve them, the utility, and other customers on the system.

The Company's presentation points to the many ways that DG customers may increase the cost on the system. Both Staff and RUCO sent out a series of discovery questions to verify the validity of the claims, discovery questions and replies attached as Exhibit_-(FWR-20) Select Discovery Questions and Replies Relating to DG. Some of the costs are still in the academic/theoretical cost category but others are not. For example, the Company has a pilot experiment for installation of advanced inverters to control PV generation at the source (See STF 1.22). If this pilot is successful, this service will be a unique cost directly attributable to DG. Company witness Tilghman points outs increased cost for load following and frequency regulation (Tilghman Direct at 8). This is a true cost but at current levels this concern seems to be for larger utility scale renewables rather than a customer with a roof-top solar unit (See RUCO3-17). With 170 MW of DG and growing by the Company's next rate case, this might grow to be a real operational concern and costs. As the saturation of DG becomes more pronounced the instances of reverse power flow conditions will increase. This will require more monitoring of load at the feeder level which is not generally done today (See RUCO 3.14-3.16).

The graph below shows some load data that I received from the Company in response to RUCO 7.11. The graph shows the average demand for a sample of almost 3,000 residential customers and the production curve for a typical roof top solar customer at the average size of applications received between January 2015 and April 2015 (See Tilghman Direct at 6:2). TEP usually experiences peaks between 5 and 7 pm so the demands placed on the system for these two types of customers are quite different. If the peak demand is at 5 pm and there are no clouds, then the DG customer is responsible for less demand on the Company's system (though the DG customer is still reliant on other grid services hidden within the bundled kWh rate). On the other hand, if the peak occurs at 7 pm, then the DG customer is placing demands on the system just like any other customer, while not necessarily covering the system costs due to a credit build up from non-peak hours. While I am not testifying that these two load shapes are 100% accurate, given the amount of data provided, I do think it illustrates the fact that a DG customer is not the same as a typical residential customer and they should not be treated the same for rate making purposes.



In my direct testimony in this case I presented a discovery response which shows that the utility does little to track partial requirement customers load shapes or usage patterns (See Exhibit FWR-11). Moreover, the Company could not produce a typical load curve for a year round residential customer but instead supplied a spreadsheet with hourly load date for a sample of over 1,600 customers. This data is relatively useless as it provides no statistically reliable data to measure load by usage. To be reliable, a stratification of customers by monthly usage must be developed, a statically significant sample would then have to be selected for each strata and hourly load data collected and then extrapolated to get a meaningful typical load pattern for a customer type. As it is, one cannot verify that the peak demand, as reported by the Company and used as an input into its cost of service study, is anywhere near accurate. I am not saying that the utility is wrong, but I am saying that the Company's presentation leaves a lot to be desired for the typical residential customer. As to the partial requirements customer, the lack of presentation provides little basis to support the price signals a 24/7 demand charge would send. This is in stark contrast to the demand charge RUCO witness Lon Huber proposes, which is grounded by system peak demand statistics. As the utility notes, the cost to serve partial requirements customers is higher than traditional full service requirements customers. Yet until the Company provides a more detailed statistical presentation, it will be hard to address the issue on highly precise terms. As such, unless the utility starts collecting and tracking detailed data by customer type, we can only make broad, but still highly justified reforms to rate design. .

Q. DOES THIS CONCLUDE YOUR RATE DESIGN TESITMONY?

A. Yes, it does.

EXHIBIT FWR-1

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Rate Setting – Dover Plains Water Company – Case 14-W-0378 -- Prepared rate filing before the New York Public Service Commission for the Dover Plains Water Company to increase its annual water revenues. 2014

Rate Setting – Village of Castile – Case No. 14-E-0358 – Prepared rate filing before the New York Public Service Commission for the Village of Castile Electric Department to increase its annual electric revenues. 2014

Depreciation Study – Village of Swanton – On behalf of the Village of Swanton, Vt. Electric Department prepared a depreciation study for use in setting new depreciation rates to be submitted to the Vermont Public Service Board. 2014

Rate Setting – Village of Hamilton – Case 13-G-0584 – On behalf of the Village of Hamilton, NY designed initial rates for new municipal gas utility. 2013

Rate Setting – Fillmore Gas Company - Case No. 13-G-0039 - Prepared rate filing before the New York Public Service Commission for the Fillmore Gas Company to increase its annual gas revenues. 2013

Rate Setting – Alliance Energy - Case No. 12-G-0256 - Prepared rate filing before the New York Public Service Commission for the Alliance Energy Transmission, LLC to increase its annual gas transportation. 2012

Rate Study – Atmos Energy – Docket No. 11-UN-184 – On behalf of the Mississippi Public Service Commission, submitted report on reasonableness of Company's depreciation study. 2012

Rate Study – Entergy Mississippi –Docket No. 11-UA-83 -- On behalf of the Mississippi Public Service Commission, prepared report on the reasonableness of Entergy Mississippi's depreciation study. 2012

Rate Case Cost of Service Study – Mississippi Power Company – On behalf of the Mississippi Public Service Commission, prepared report on reasonableness of embedded cost of service study submitted by Mississippi Power Co. 2012

Rate Case Cost of Service Study – Boonville, NY – Prepared class load study and embedded cost of service study to justify change in rate design for the purpose of conserving energy. 2010-2012

Rate Setting – Alliance Energy Transmission - Case No. 12-G-0256 – Prepared rate filing before the New York Public Service Commission for Alliance Energy Transmission. 2012

Rate Setting – Hamilton, NY - Case No. 12-E-0286 - Prepared rate filing before the New York Public Service Commission for the Village of Hamilton, NY to increase its annual electric revenues. 2012

Rate Setting – Fairport, NY – Case No. 11-E-0357 - Prepared rate filing before the New York Public Service Commission for the Village of Fairport, NY to increase its annual electric revenues. 2011

Jurisdictional Cost of Service – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

Rate Analysis – Southwestern Power Company – On behalf of a coalition of retail customers analyzed reasonableness of utility's request to include the costs of Construction Work In Progress Expenditures in rates for a power plant known as the Turk Plant. 2010

Rate Study – Stowe Electric Department, VT – Docket No. 8169 – For small municipal electric utility, filed rate case before the Vermont Public Service Board. 2010

Docket No. 10-10-03 – Assisted in the CT OCC's review and development of recommendations for the Review of the 2011 Conservation and Load Management Plan. 2010

Rate Setting – Endicott, NY - Case No. 10-E-0588 – Prepared rate filing before the New York Public Service Commission for the Village of Endicott, NY to increase its annual electric revenues. 2010

Rate Case Cost of Service Study – Heritage Hills Water Works – For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Setting Training – MMWEC – Assisted in training MMWEC staff on rate setting process so that they could provide service to members. 2009

Rate Setting – Connecticut Natural Gas -- Docket No. 08-12-06 - Assisted the Connecticut Office of Consumer Counsel on the analysis of the reasonableness of the of the Company's proposed revenue requirement. 2009

Rate Filing – Heritage Hills Water Works – Case No. 08-W-1201 – Prepared rate filing before the New York PSC for the Heritage Hills Water Works Corporation to increase its annual water revenues. 2008

Rate Study – Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation. 2008

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reductions control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 9344 – Green Ridge Utilities – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2014

FC 1115 – Washington Gas Light -- On behalf of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal for the recovery of costs and funding aspects of Washington Gas Light Company's Revised Accelerated Pipe Replacement Plan. 2014

Case No. EC-123-0082-00 – Entergy Mississippi – On behalf of Mississippi Public Utilities Staff reviewed and testified on the reasonableness of Entergy Mississippi, Inc.'s proposed depreciation rates and cost of service study. 2014

Case 9345 – Maryland Water Services – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2014

Case No. 2013-00167 – Columbia Gas of Kentucky – On behalf of the Office of Rate Intervention of the Attorney General for the Commonwealth of Kentucky testified on the reasonableness of the Company proposed rate increase. 2013

Docket 13-G-1301 – Consolidated Edison – On behalf of US Power Generating Company testified on the reasonableness of proposed modifications to natural gas balancing services. 2013

Docket No. 13-01-09 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2013

Case U-17169 - Semco Energy - On behalf of the Michigan Department of Attorney General testified on the reasonableness of the Company's proposal to modify its accelerated main replacement form for gas distribution facilities. 2013

Docket No. 13-06003 – Sierra Power Company - On behalf of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2013.

Docket No. E-01 933A-I 2-0291 – Tucson Electric Power -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's rate increase. 2012

Case No. FC 1093 - Washington Gas and Light – On behalf of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal to replace and/or remediate certain gas distribution facilities that are subject of this case, 2012.

Docket No. C-2011-2226096 — Pennsylvania American Water Co. - In a class-action lawsuit, testified before the PA PUC on behalf of C. Leslie Pettko on the reasonableness of the surcharges imposed by Pennsylvania American Water Company. 2012

Docket No. 11-06007 – Nevada Power Company – On behalf of the Nevada Public Service Commission, testified on the reasonableness of the Company electric depreciation study on Nevada Power Co. 2011

MEUA –On behalf of the Municipal Electric Utilities Association, filed testimony with the New York Power Authority (NYPA) on the reasonableness of the Authority's 2011 Rate Modification Plan for the Niagara Power Project. 2011

Case No. 9283 – Green Ridge Utilities, Inc. – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2011

Case No. 11-G-0280 – Corning Natural Gas -- On behalf of the Village of Bath, NY, analyzed the construction program, revenue requirement, and rate design proposed by the gas distribution company serving the Village. 2011

Case No. 10-G-0598 – Bath Electric Gas and Water Systems - Testified as to the reasonableness of the Village of Bath's request for a refund relating to overcharges for gas purchased from the Corning Natural Gas Co. 2011

Case No. U-16472 – Detroit Edison -- On behalf of four large hospitals – Detroit Medical Center, Henry Ford Health Systems, William Beaumont Hospital, and Trinity Health Michigan – testified on the reasonableness of the continuation of a service class for large customers with special contracts. 2011

Case No. 9252 – Artesian Water Maryland, Inc. - On behalf of the Maryland Office of People's Counsel, analyzed proposed revenue requirement of Artesian Water Maryland, Inc. 2011.

Case No. 10-E-0362 – Orange and Rockland Utilities, Inc. - On behalf of a coalition of municipalities, testified on the reasonableness of the proposed revenue requirement of Company. 2010.

Docket No. 05-10-RE04 – Connecticut Light and Power Co. – On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the assist in its review of the application of Company for approval of full deployment of its Advance Metering Infrastructure ("AMI"). 2010

Docket Nos. 10-06003 and 10-06004 – Sierra Power Company - On behalf of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2010.

Case No. 10-E-0050 – Niagara Mohawk Power Corporation -- On behalf of a coalition of municipalities, testified on the reasonableness of utility's proposal to eliminate contracts to provide street lighting service. 2010

Case No. 9248 – Maryland Water Services - On behalf of the Maryland Office of the People's Counsel, testified on the reasonableness of the proposed revenue requirement of Maryland Water Services, Inc. 2011

Docket No. 10-12-02 – Yankee Gas Services Company -- On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the Company's proposed depreciation rates. 2010

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities, Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 – Connecticut Water Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 – Connecticut Light & Power Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel of the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 -- UNS Gas, INC. -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 – Arizona Public Service – On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in depreciation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 – Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdrola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2012 – Speaker accelerated main replacement programs

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association
Northeast Public Power Association
New York State Independent System Operator

EXHIBIT FWR-2

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 28, 2016

RUCO 8.06

Hutchens Direct 13:11-24 – 18:1-18 - Please provide the monthly energy sales for TEP's retail delivery customers from January 2006-December 2015 on an actual basis and weather normalized basis.

RESPONSE:

Please see RUCO 8.06.xlsx for the monthly weather normalized sales. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-3

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 28, 2016

RUCO 8.05

Hutchens Direct 13:11-24 – 18:1-18 - Please provide the monthly peak demand for TEP's retail delivery customers from January 2006-December 2015 on an actual basis and weather normalized basis.

RESPONSE:

Please see file RUCO 8.05 City Load Data.xlsx, sheet "Monthly Summary" for the monthly peak data requested. The Excel file is <u>not</u> identified by Bates numbers. The Company cannot provide weather normalized peak data as it does not perform such adjustments. This is because the peak model has a high degree of complexity, thus making peak normalizing very difficult and normalized peak values are of little value for system planning.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-4

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
February 26, 2016

STF 3.3

Jurisdictional Allocations: Please provide the workpapers and supporting documents used to derive the jurisdictional allocations used for each pro-forma adjustment.

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Please see STF 3.3 Jurisdictional Allocation-Confidential.xlsm. The Excel file is not identified by Bates numbers.

Within this file, extracts for the Rate Base-Orig Cost and Rev-Exp tabs were taken from UDR 1.001 – 2015 TEP Rev Req Model.xlsm.

The jurisdictional allocation calculation and the ACC Jurisdiction pro-forma adjustments are shown in columns AF – BS of the Rate Base-Orig Cost Tab and columns BZ-FM of the Rev-Exp Tab.

Each individual cell formula within these columns support the jurisdictional allocations.

Also included in the Excel file provided herein are separate supporting tabs for the following allocators:

1. Demand
2. Energy
3. Ancillary
4. Payroll

RESPONDENT:

Anne Liu

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY
ACC/FERC JURISDICTION - DEMAND ALLOCATION FACTOR

Line No.	Date	Retail System Peak	SRP	NTUA	TOUA	Shell	Trico	Sub-Total FERC	Removes SRP & Shell	Total	Line No.
		DEMAND ALLOCATON - 2015									
		(a)	(b)	(c)	(d)	('e)	(f)	(g)	(h)	(i)	
1	June, 2015	2,206	100	41	5	100	50	296	96	2,302	1
2	July, 2015	2,066	100	48	5	100	50	303	103	2,169	2
3	August, 2015	2,214	100	40	5	100	50	295	95	2,309	3
4	September, 2015	1,995	100	35	5	100	50	290	90	2,085	4
5	Total	8,481						1,185	385	8,866	5
6	Average (Line 5/ 4)	**2,120.25**							**96.2**	**2,216.5**	6
7	Demand Allocation Factor (Line 6 - (a)/(i) and (h)/(i)	95.66%							4.34%		7

EXHIBIT FWR-5

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Salt River Project Agricultural	LF	Tariff 3 S.A. 12			
2	Improvement and Power District					
3	Navajo Tribal Utility Authority	LF	Tariff 3 S.A. 11			
4	Tohono O'odham Utility Authority	LF	Tariff 3 S.A. 13			
5	Shell Energy North America (US) LP	LF	WSPP			
6	EDF Trading North America, LLC	LF	ISDA			
7	Trico Electric Cooperative	LF	Tariff 3 S.A. 13			
8	Ajo Improvement District	SF	AJO Contract			
9	Morenci Water and Electric	SF	Morenci Agreement			
10	Arizona Electric Power Cooperative	SF	WSPP			
11	Arizona Public Service Company	SF	WSPP			
12	Black Hills Power, Inc.	SF	WSPP			
13	BP Energy Company	SF	ISDA			
14	Cargill Power Markets, LLC	SF	ISDA			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

- Privileged Data

EXHIBIT FWR-6

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC TWELFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 2, 2016

AECC 12.4

Please identify the margins earned by TEP on the Shell Long Term Energy Sales contract for each month since its effective date.

RESPONSE: **April 19, 2016**

The Company objects to this question as it relates to non-ACC jurisdictional margins that are outside the scope of this rate case.

RESPONDENT:

Jeanine Tracey

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: **May 2, 2016**

Per discussions between counsel for the Company and counsel for AECC, please see AECC 12.4-12.6 4-12-16 (Test Year)-Competitive Sensitive Confidential.xlsx. The Excel file is not identified by Bates numbers.

The Shell contract was put into place after the acquisition of Gila River Unit 3. The contract expires December 31, 2017.

RESPONDENT:

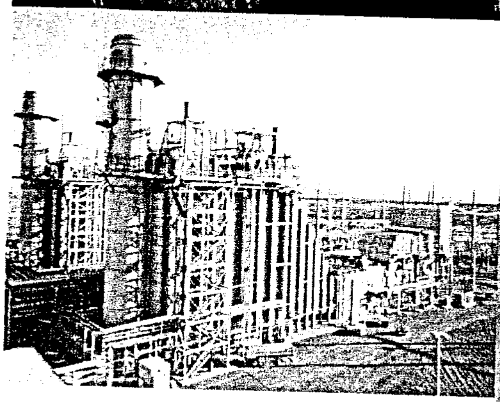
Jeanine Tracey / Michael Sheehan

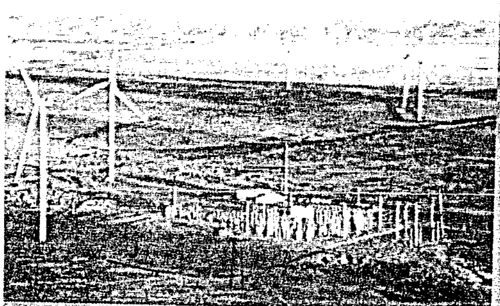
WITNESS:

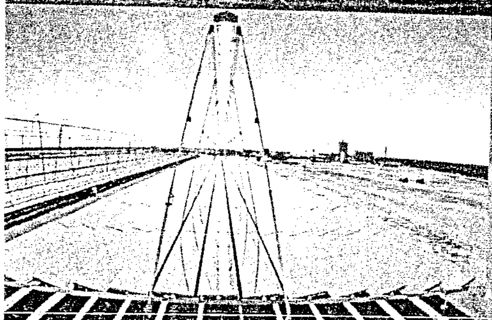
Dallas Dukes

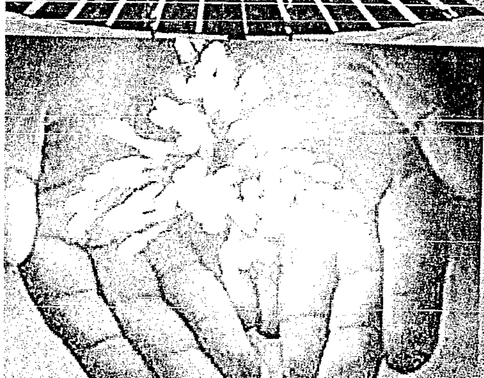
EXHIBIT FWR-7

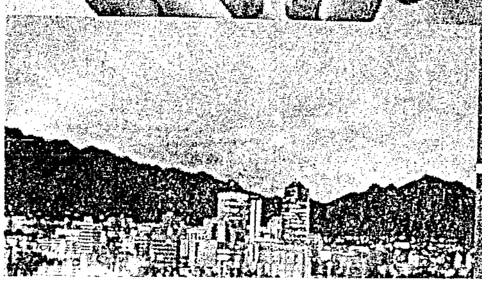
TUCSON ELECTRIC POWER











2014 Integrated Resource Plan

April 1, 2014

EXHIBIT FWR-8

CONFIDENTIAL

EXHIBIT FWR-9

CONFIDENTIAL

EXHIBIT FWR-10

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.03

Weather Normalization – Please provide the results and adjustment to test-year revenue by year under the Company's new model if a nine year, eight year, seven year, six year, five year, four year, and three year model were used. In addition, please provide the statistical outputs, such as p-values and r-squared values associated with each year requested above.

RESPONSE:

The Company objects to the request as it is overly burdensome. The time required to generate each of the models above and to calculate the total adjusted revenue is significant. Please see RUCO 7.05b for an explanation as to why this process is highly burdensome and resource intensive.

For the model statistics of the model the Company used for the weather normalization, please see file RUCO 7.03 TEP Weather Normalization Model Statistics.pdf, Bates Nos. TEP\021852-021889.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.04

Weather Normalization – Please provide the results and adjustment to test-year revenue under the Company's new model if a fifteen year, twenty year, twenty five year and thirty year model were used. In addition, please provide the statistical outputs, such as p-values and r-squared values associated with each year requested above.

RESPONSE:

Please refer to RUCO 7.03.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

EXHIBIT FWR-11

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.11

Residential Customers - RE: Dukes Direct at page 11:22-25, please provide the following:

a. the number of seasonal residential customers that TEP has together with their energy use, by month, for a typical year;

b. the number of year round residential customers that TEP has together with their energy use, by month, for a typical year;

c. the estimated number of residential vacant homes, by month, for the years 2011-2015.

d. Please provide typical load profiles for a residential seasonal customer, a residential vacant home, a residential year round customer, and a residential customer with distributed generation. The load profiles should be for the winter period, the summer period, and the peak day.

RESPONSE:

a./b. The Company does not currently track seasonal versus year round customers and therefore does not have their energy use as requested.

c. The Company does not track vacant homes.

d. For the reasons above, the company does not have load profiles for the requested customer types. The company has a large swath of hourly data for a number of customers which include some of the customer types listed. Although there are not distributed generation customers in the sample, the Company is also including the NREL SAM 8760 production curve for the Tucson area for use in estimating solar DG customer hourly load shapes.

Please see the following files for the 8760 production curve.

File Name	Bates Numbers
RUCO 7.11 Individual Customer Sample 2-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 3-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 4-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 5-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample-Confidential.xlsx	N/A
RUCO 7.11 NREL SAM DATA-Confidential.xlsx	N/A

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-12

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 28, 2016

RUCO 8.04

Re: Response to RUCO 3.11 and Dukes Direct at 14:6-9 - FERC Form 1 data shows that the UPC for Residential rate class has been declining since 2007 when it peaked at 10,922 kWh per year (See 2007 FERC Form 1, page 304, column e, line 2). For 2007 please provide the weather normalized UPC. For each year 2008-2015, please provide the actual annual UPC for the Residential Regular service class together with the UPC change due to DG, due to energy efficiency and due to economic changes.

RESPONSE:

Please see the table below for the breakout of weather normalized residential UPC and the change due to EE and DG. Please note, when the Company performs the weather normalization, that the Company weather normalizes the entire residential class and not just R01. This is why the Company is starting with the 2007 UPC of 11,129 instead of 10,922. The Company cannot accurately quantify what is due to economic changes versus some other effect. Thus the values are labeled as other changes.

Year	Residential UPC	Weather Normalized UPC	Y/Y EE Change	Y/Y DG Change	Y/Y Other Change
2007	11,129	10,956			
2008	10,621	10,802	(9)	(2)	(144)
2009	10,708	10,713	(24)	(3)	(62)
2010	10,579	10,579	(45)	(7)	(82)
2011	10,606	10,450	(140)	(29)	40
2012	10,375	10,350	(174)	(32)	106
2013	10,424	10,108	(182)	(50)	(10)
2014	9,960	9,805	(265)	(38)	1
2015	9,894	9,684	(231)	(78)	189

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-13

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 2, 2016

RUCO 7.20

TEP Headquarters – Please answer the following questions as they relate to the TEP Headquarters:

a. Based on the Company's last rate case the Company identified the following two components of building costs:

TEP New HQ-IT	$ 7,363,145
TEP New HQ-Facilities	$ 84,604,455
Total	$ 91,967,600

Please update these two cost components to reflected other capital improvements and/or additions. Further, update the response for any other capitalized cost component not already reflected in these two components. In addition, include the FERC sub account numbers for these capitalized assets and amounts (e.g. 311 Structures and Improvements).

b. Based on the Company's last rate case the Company identified the following cost per square foot.

Office	$263/sf
Retail	$178/sf
Parking	$64/sf

Please update these costs to reflect the current cost per square foot for the above three areas. In addition provide the work sheets, and calculations to substantiate the response.

c. Do the dollar per square foot (Office, Retail, Parking) cited in b. include a capitalized portion and an operating and maintenance ("O&M") expense portion?

d. If no to c. provide the capitalized portion and the O&M portion per square foot. Further providing a listing of components that are listed in the capitalized and O&M portions (e.g. property taxes, depreciation expense, etc.).

e. Based on the Company's last rate case, the Company indicated that 12,000 gross square feet of retail space was unused. Please update the gross square feet of retail space to reflect both used and unused space.

f. Based on the Company's last rate case, the Company indicated that 8,540 gross square feet of vacant and unused cubical space. Please update the gross square feet of office space to reflect both used and unused space.

g. Please provide the gross square feet of parking space to reflect both used and unused space.

h. List by floor and square footage the portion of the building that has been allocated to TEP employees, UNS electric employees, UNS gas employees, and any other TEP affiliates.

i. List by floor and square footage the portion of the building that is rented/leased to other non-affiliate entities (e.g. insurance company)?

j. Is a profit component built into the rental/lease payment that each affiliate member pays to the parent company, if so, what is that percentage, and what is the amount of profit charged to each affiliate member?

k. Is a profit component built into the rental/lease payment that each non-affiliate member pays to the parent company, if so, what is that percentage, and what is the amount of profit charged to each non-affiliate member?

RESPONSE: **April 18, 2016**

TEP is in the process of gathering this information and will provide it as soon as possible

RESPONDENT:

Anne Liu

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: **May 2, 2016**

a. The cost components for the TEP Headquarters at June 30, 2015 are as follows:

FERC Sub Account	Description	Net
E397	Communication Equipment	$ 714,308
E391-CP	Computer Equip.	3,574,387
	TEP HQ-IT Total	4,288,695
E390	Structures & Improvements-General Plant	68,371,896
E391-OE	Office Equip	1,331,752
E389-LD	Land	8,549,938
E398-RW	Right a ways	41,468
	TEP HQ-Facilities Total	78,295,053
	Total at June 30, 2015	$ 82,583,748

b. The cost per square foot provided in the last rate case was an approximation based on total construction costs and gross square footage. Construction costs included land, direct construction costs for shell building, permits, impact fees, etc. For your reference, please see file RUCO 7.20.pdf, Bates Nos. TEP\023766-023770, for the response to STF 22.06 (r) provided in the 2012 TEP Rate Case.

The net balance of the HQ Building decreased by 11.62% as compared to the balance in the last rate case. To provide an approximation of the current cost per square feet, the prior amounts were decreased accordingly.

	June 30, 2015	Dec. 31, 2011	Change
Cost	98,679,260	94,745,693	
Reserve	(16,095,511)	(1,300,437)	
Net Balance	82,583,748	93,445,256	-11.62%

	Cost Per Square Ft - Adjusted by % Change	
	Prior Rate Case	Current
Office	263	232
Retail	178	157
Parking	64	57

c. No, it does not include an O&M expense portion. The cost per square foot figures in the last rate case were based on capitalized one-time construction costs. It included land costs, direct construction costs, and one time sales tax/ plans, permits and impact fees.

d. The Company does not maintain dollar per square foot data by Office, Retail, Parking for capitalized and O&M expenses. As noted above, the total capitalized portion of the building is $82,583,748 at June 30, 2015.

Expenses for the test year by component are:

O&M Expense	1,657,958
Property Taxes	1,111,450
Depreciation	3,881,648
	6,651,056

e. The 12,000 square footage of retail space supplied in the last rate case should be revised to 10,185. It is 100% unused.

f. The square footage of space built out excluding retail and the garage levels is 267,625. This includes workstations, offices, hallways, common areas, rest rooms, mechanical rooms, etc. Of the 267,625 total square footage, 263,365 square feet is used. 4,260 square feet is unused workstation and office space.

g. The square footage of the parking space is 224,600. 100% used.

h. The headquarters building is 100% occupied by TEP employees or contract personnel doing work on behalf of TEP, UNS Electric and UNS Gas.

i. None of the headquarters building is currently being rented/leased to others.

j. There are no rental/lease payments from affiliate members for the headquarters as the building is 100% occupied by TEP. However, within the building allocation cost charged to affiliates, through a labor allocation; a return component of 5.04% as per the agreed upon return in the last rate case.

k. Not applicable. There are no rental/lease payments paid by non-affiliated members.

RESPONDENT:
Anne Liu (a, b, c, d, h-k) / Ryan Companies (e, f, g)
WITNESS:
Dallas Dukes

EXHIBIT FWR-14

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 7, 2012

RUCO 7.13

Did TEP conduct a comprehensive cost-benefit analysis of building a new headquarters versus maintaining the existing facilities? If so, please provide the analysis. If not, why not?

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

The Company did an extensive evaluation before it decided to proceed with a new headquarters building. Management began considering adding and consolidating office space in mid-2007; a final decision to purchase the land for a new building was made in April 2009 and a final decision to begin building was made in October 2009. TEP was considering new space for numerous reasons including:

a. Even with the use of the temporary office trailers, the current facilities were at 99% occupancy and, in certain cases, TEP needed to rent space for project teams;

b. The lease at One South Church, where 80 employees were located, was up for renewal in June 2011;

c. Over 300 employees at the Irvington Campus were housed in 12 temporary office trailers that were costly to operate, and the employees were functionally separated from the other work groups;

d. Two permanent office facilities at the Irvington site (one built in the 1950's and one in the early 1980's) were due for renovation and mechanical upgrades (i.e., HVAC, bathrooms, ADA compliance, etc.);

e. TEP needed more conference space and larger conference/auditorium to facilitate employee meetings—at the time, the largest conference room could only handle 125 people, a small percentage of our employees based in Tucson at that time;

f. For compliance and business continuity reasons, the Company was evaluating backup locations for its IT data center, call center, control room and physical security. TEP met the need for backup facilities by incorporating them into the new secure headquarters.

g. The decision to proceed in the 2009-2010 time frame, which coincided with the weak economy, provided the opportunity to build a new headquarters at a reasonable lower cost level and support construction related jobs in Tucson;

Given the Company's situation, it developed objectives and a plan to resolve the long term office needs. The primary objectives included: a) eliminate existing capacity constraints and provide for growth; b) consolidate employees into fewer office locations to improve communications and reduce travel time and costs; c) consolidate all or at least a major portion of the corporate staff functions into one building to improve communications and reduce travel time and costs; d) choose office location(s) and parking that is convenient and safe for employees; and e) manage costs. In addition to the primary objectives, the Company also wanted to choose an office facility that was environmentally friendly (i.e., incorporating energy efficiency and renewable energy resources) and supported the Tucson community with economic development and/or office common facilities that could be used by the community including local charities.

To meet the objectives, the Company investigated and evaluated various alternatives. It compared the alternatives of a) expanding/remodeling current facilities; b) leasing additional space at One South Church Avenue; c) leasing existing office space at other Tucson locations; d) buying existing office space in Tucson; and e) building a new office building at numerous locations in Tucson. Please see the files listed below for the confidential materials that set forth the analyses conducted in connection with these options and the ultimate decision to build the new corporate headquarters.

File Name	Bates Numbers
RUCO 7.13 New Building Pres 2008 08-2011 12-Confidential.pdf	TEP\027864-027949
RUCO 7.13 NewBuildPresExh2009 04-HumanImpact-Confidential.pdf	TEP\027950-027978
RUCO 7.13 NewBuildPresExh2009 04-Irvington Modulars-Confidential.pdf	TEP\027979-027981
RUCO 7.13 NewBuildPresExh2009 04-ListDscrpProps-Confidential.pdf	TEP\027982-028006
RUCO 7.13 NewBuildPresExh2009 04-Map187482-Confidential.pdf	TEP\028007-028008

Based on the analyses and TEP's needs, it was ultimately determined that the best alternative was to build a corporate headquarters at 88 East Broadway. The key drivers in the decision were: a) there was not suitable existing office space of at least 100,000 square feet with parking for 250 employees available in Tucson; b) building a new building allowed the Company to design for its specific use and needs; c) building a new building allowed the facility to be sized to consolidate a larger number of employees into one location based on a space planning/adjacency study (see Response to RUCO 7.12); d) the downtown location is convenient for employees for commuting including access to public transportation and the downtown location supports the development of downtown Tucson; and e) the slow economy and weak construction industry allowed the company to closely manage costs, to build the facility in a short, tight time period and to provide jobs/economic activity to the local Tucson economy.

RESPONDENT:

Scott Rathbun/Kevin Larson

WITNESS:

Michael DeConcini

EXHIBIT FWR-15

CONFIDENTIAL

EXHIBIT FWR-16

CONFIDENTIAL

EXHIBIT FWR-17

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 7, 2012

RUCO 7.23

When was ownership of the new facility transferred to Tucson Electric Power Company from UniSource, and why did this transfer occur?

RESPONSE:

The transfer date was November 1, 2011. The building was initially owned by UNS to provide greater flexibility in financing the asset construction. The transfer of ownership made economic and practical sense for many reasons, including:

1. UNS initially attempted to attain New Markets Tax Credits for the building, which were available for development in certain areas. The credits were available to a developer/lessor (a role UNS could have fulfilled by owning the building and leasing it to TEP), but were not available to an owner occupant such as TEP. When it became clear that the tax credits would not be available for this development project, it made more economic sense for TEP to own the asset directly rather than UNS (see additional reasons below).
2. TEP avoided a potential liability on its balance sheet by owning the asset instead of entering into a long-term lease obligation;
3. Use of the facility by TEP was ensured over the long-term, avoiding the need to consider purchase and lease renewal options at end of the lease term; and
4. Long-term financing for the facility could be obtained on better terms at TEP due to TEP's investment-grade credit rating (UNS is rated Ba1, a non-investment grade credit rating).

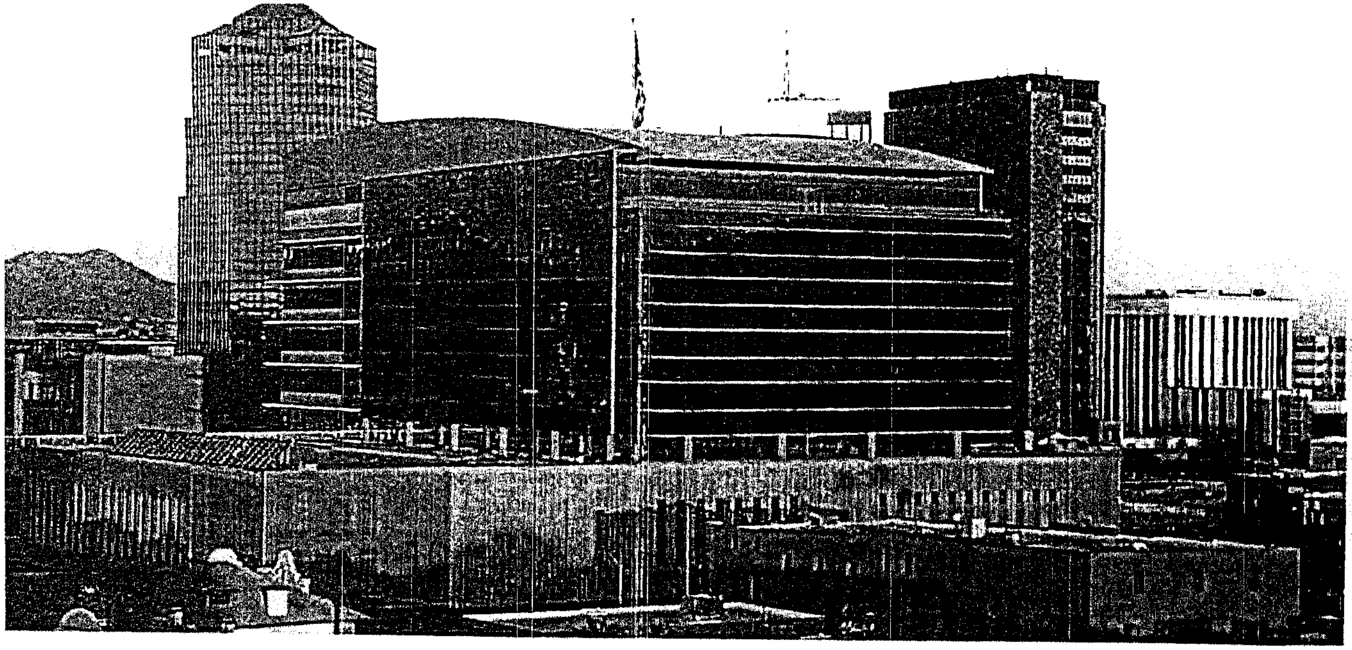
RESPONDENT:

Scott Rathbun, Karen Kissinger and Kentton Grant

WITNESS:

Michael DeConcini

EXHIBIT FWR-18



JniSource Energy's corporate headquarters s a showcase of green construction and design. Completed in November 2011, the building supports the efficient, effective operations of Tucson Electric Power (TEP) and UniSource Energy Services (UES) JniSource Energy's utility subsidiaries.

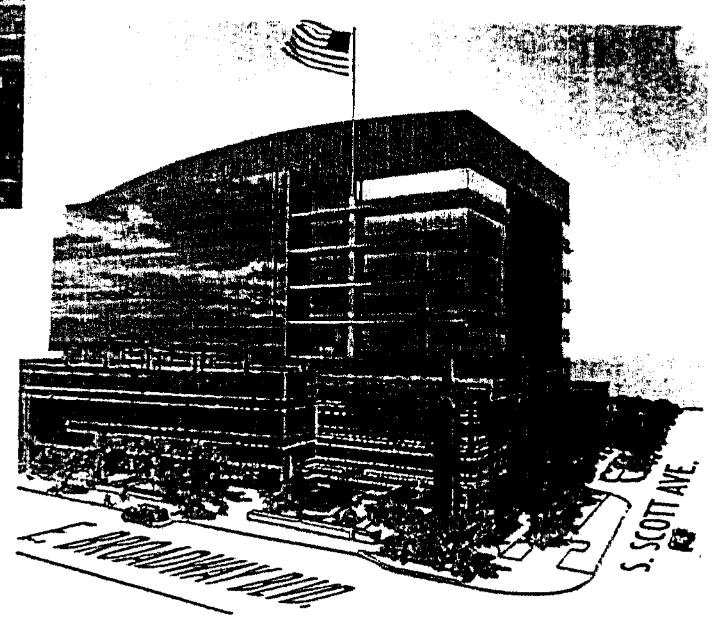
'he nine story building provides 232,000 quare feet of space for more than 500 mployees. It also includes 11,000 square eet of ground-floor retail space, a state-f-the-art conference center, on-site arking and a long list of environmentally esponsible features.

UniSource Energy's corporate headquarters exemplifies the company's commitment to leadership in energy efficiency and renewable energy.

For more information about the green programs available to UniSource Energy's utility customers, visit tep.com or uesaz.com

BRIGHT SOLUTIONS™
from UniSource Energy

There's a New Energy Downtown



UniSource Energy's solar-powered, energy-efficient Tucson headquarters

BRIGHT SOLUTIONS™
from UniSource Energy

EXHIBIT FWR-19

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	**UNISOURCE ENERGY CORPORATION** (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	**TUCSON ELECTRIC POWER COMPANY** (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	**Common Stock, no par value**	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation	Yes þ	No o
Tucson Electric Power Company	Yes o	No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation	Yes o	No þ
Tucson Electric Power Company	Yes þ	No o

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such

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Cash used for investing activities is primarily a result of capital expenditures at TEP, UNS Gas and UNS Electric. Cash used for investing and financing activities can fluctuate year-to-year depending on: capital expenditures, repayments and borrowings under revolving credit facilities; debt issuances or retirements; capital lease payments by TEP; and dividends paid by UniSource Energy to its shareholders.

Operating Activities

In 2009, net cash flows from operating activities were $70 million higher than 2008 primarily due to: lower costs of fuel and purchased energy; increased retail revenues due to base rate increases at TEP and UNS Electric and hot summer weather; lower interest paid on capital leases and long-term debt; partially offset by lower wholesale sales, higher O&M and higher wages paid.

Investing Activities

Net cash used for investing activities was $156 million lower in 2009 compared with 2008 due to: a $133 million deposit made by TEP last year with the trustee for bonds that matured on August 1, 2008; and a $70 million decrease in capital expenditures in 2009; partially offset by a $31 million investment made by TEP in 2009 to purchase Springerville lease debt; and a $12 million decrease in proceeds from investment in lease debt.

Capital Expenditures

	Actual	Estimated				
Business Segment	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
			-Millions of Dollars-			
TEP	$ 235	$ 258	$ 217	$ 203	$ 225	$ 209
UNS Gas	14	14	16	16	16	18
UNS Electric	28	26	25	31	13	16
UniSource Energy Stand-Alone	10	16	27	1	—	1
UniSource Energy Consolidated	$ 287	$ 314	$ 285	$ 251	$ 254	$ 244

- Included in TEP's capital expenditures forecast for 2010 is $52 million for the proposed purchase of Sundt Unit 4.
- Items excluded from TEP's capital expenditures forecast are: the estimated cost to construct proposed Tucson to Nogales, Arizona transmission line of $120 million; estimated costs of $300 million between 2011-2014 to construct 75 to 150 MW of local generation that may be required in 2015.
- The estimated capital expenditures for UniSource Energy Stand-Alone are for the purchase of land and construction of a new corporate headquarters.

For more information see *TEP, Liquidity and Capital Resources, Investing Activities, Capital Expenditures,* below, and *Item 1. Business, TEP, Transmission Access, Tucson to Nogales Transmission Line,* above.

Financing Activities

Net cash proceeds from financing activities were $170 million lower in 2009 compared with 2008. In 2008, The Industrial Development Authority of Pima County issued, for the benefit of TEP, approximately $221 million of tax-exempt industrial development revenue bonds and UNS Electric issued $100 million of long-term debt used in part to refinance a $60 million debt maturity. Factors affecting proceeds from financing activities in 2009 included: $30 million of proceeds from the issuance of short-term debt at UED; a $70 million decrease in payments of long-term debt compared with 2008; a $50 million decline in payments on capital lease obligations compared with 2008; and a $7 million increase in dividends paid compared with 2008.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2010

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	UNISOURCE ENERGY CORPORATION (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	TUCSON ELECTRIC POWER COMPANY (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation	Yes þ	No o
Tucson Electric Power Company	Yes o	No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation	Yes o	No þ
Tucson Electric Power Company	Yes þ	No o

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

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Capital Expenditures Forecast

Business Segment	Actual 2010	2011	2012	Estimated 2013	2014	2015
			-Millions of Dollars-			
TEP	$ 267	$ 306	$ 273	$ 372	$ 322	$ 286
UNS Gas	10	12	11	14	16	22
UNS Electric (1)	22	37	51	25	30	32
Other Capital Expenditures	17	36	1	—	—	—
	$ 316	$ 391	$ 336	$ 411	$ 368	$ 340

(1) UNS Electric is expected to purchase BMGS from UED for approximately $62 million during 2011. Since this is an inter-company transaction, it is not included in the chart, as it is eliminated from UniSource Energy consolidated capital expenditures. See *UNS Electric, Factors Affecting Results of Operations, Rates, 2010 UNS Electric Rate Order,* below, for more information.

TEP's capital expenditures in 2010 include $52 million for the purchase of Sundt Unit 4. TEP's estimated capital expenditures in 2015 exclude the potential purchase of Springerville Unit 1 and Springerville Coal Handling Facilities upon the expiration of their respective leases in January 2015.

Other capital expenditures reflect UniSource Energy's standalone capital expenditures, including the purchase of land and construction costs for a new corporate headquarters.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to changes in business conditions, construction schedules, environmental requirements, state or federal regulations and other factors.

For more information regarding TEP's capital expenditures, see *Tucson Electric Power Company, Liquidity and Capital Resources, Investing Activities, Capital Expenditures,* below.

Financing Activities

Net cash proceeds used for financing activities were $22 million higher in 2010 than they were in 2009 due to:

- $30 million of net revolving credit facility repayments in 2010 compared with net proceeds of $5 million in 2009;
- a $32 million increase in payments of capital lease obligations;
- $30 million of short-term debt proceeds in 2009 compared with none in 2010; and
- a $15 million increase in dividends paid to common shareholders; partially offset by
- an $82 million increase in proceeds from long-term debt net of repayments of long-term debt.

Capital Contributions

In the first quarter of 2010, UED paid a $9 million dividend to UniSource Energy, of which $4 million represented a return of capital distribution. In March 2010, UniSource Energy contributed $15 million in capital to TEP to help fund the purchase of Sundt Unit 4.

In 2009, UED paid a $30 million dividend to UniSource Energy which also represented a return of capital distribution. UniSource Energy used the proceeds to contribute $30 million of capital to TEP to purchase lease debt related to Springerville Unit 1.

See *Other Non-Reportable Business Segments, UED* and *Tucson Electric Power Company, Liquidity and Capital Resources*, below for more information.

UniSource Credit Agreement

In November 2010, UniSource Energy amended and restated its existing credit agreement (UniSource Credit Agreement). The UniSource Credit Agreement had previously included a $30 million term loan facility and a $70 million revolving credit facility. As amended, the UniSource Credit Agreement consists of a $125 million revolving credit and revolving letter of credit facility. The UniSource Credit Agreement will expire in November 2014. At December 31, 2010, there was $27 million outstanding at a weighted average interest rate of 3.26%.

EXHIBIT FWR-20

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.14

Re: Grey Direct at 21:10-15, please provide any and all engineering analysis to support the statements that 1) with more distributed generation resources being deployed on the TEP distribution system puts demands on the T&D systems not previously contemplated. To meet these new demands, 2) requires TEP to utilize technology to add more sensing and measurement devices and new methods for managing and operating the distribution system.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

1)

File Name	Bates Numbers
RUCO 3.14 Los Reales Feeder 14 backflow-Confidential.pdf	TEP\021154-021155
RUCO 3.14 Sample Feasibility Study 100515-Redacted-Confidential.pdf	TEP\021156-021165

Please see the following technical articles with web addresses provided:

- Reiman, A. (2015). An Analysis of Distributed Photovoltaics on Singe-Phase Laterals of Distrution Systems. *D-Scholoarship Institutional Respository at the University of Pittsburg* [Website]. Retrieved from http://d-scholarship.pitt.edu/24047/.
- Jan-E-Alam, M., Muttaqi, K.M., and Sutanto, D. (2011, July 24-29). Assessment of distributed generation impacts on distribution networks using unbalanced three-phase power flow analysis. *IEEE.org* [Website]. Retrieved from http://ieeexplore.ieee.org/xpl/articleDetails.jsp?tp=&arnumber=6039789&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D6039789
- Tang, J.H., Lim, Y.S., Morris, S., and Wong, J. (2012). Impacts on Centrally and Non-Centrally Planned Distributed Generation on Low Voltage Distribution Network. *International Journal of Smart Grid and Clean Energy*. Retrieved from http://www.ijsgce.com/uploadfile/2012/1016/20121016114245643.pdf.

1) The distribution network was designed to provide power flows from the substation to the customer. By adding generation at the customer level to feed into the distribution network voltage, power quality, protection schemes, network losses and load balancing of feeders is affected differently than the system was originally designed. Please see RUCO 3.14 Sample Feasibility Study 100515-Redacted.pdf for a sample TEP feasibility study indicating the work performed and issues identified. This type of study is typically performed for all interconnection's greater then 1MW in size. For reference are actual measurements taken from a TEP distribution feeder indicating power flow unbalance that has been introduced into the distribution network from DG sources. Please see RUCO 3.14 Los Reales back flow-Confidential.pdf for example. For reference are three other technical

articles describing the complexity in accurately modeling the effects of DG on a distribution network and the effects of DG sources on the distribution network.

2) Electrically modeling the distribution network is a complicated activity. The model is being further complicated by the introduction of DG items such as energy efficiency, solar, storage and demand response. For reference refer to the technical articles referenced for part 1. To validate the model information sensing and measurement devices can be installed to provide electrical parameters that can be incorporated in different ways (i.e. state estimation) to validate or modify the electrical model to represent actual measurements. This corrects the model to better model the actual electrical system. With better information and modeling, management and operation of the distribution network can be improved. Where improvement refers to the management of side effects caused by DG on the distribution network. The common side effects are described the technical articles referenced in part 1.

RESPONDENT:

Jim Taylor

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.15

Re: Grey Direct at 22:1-2, please provide any and all engineering analysis to support the statement that there is a need for a communications network that allows for intelligent electronic devices to be installed on the distribution system.

RESPONSE:

No engineering analysis is required to support this statement as the creation of a smarter grid is founded on the premise that new devices and technology will be implemented. The implementation is founded on the concept of having communications to provide status, alarms and control of the devices. This enables abilities such as remote control, abnormal condition indication and automated operation of devices. These type of capabilities are enabled through communications. Without communications these type of capabilities will not be able to be realized.

RESPONDENT:

Jim Taylor

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.16

Re: Grey Direct at 22:5-8, please provide any and all engineering analysis to support the statement a distribution management system is the central software application that is needed to provide distribution supervisory control and data acquisition, outage management and geographical information into a single operations view. Also, please provide a description of the current distribution supervisory control system that TEP uses and how it is different than what is contemplated to be used in the future.

RESPONSE:

No engineering analysis is required to support this statement. For discussion purposes a simple description of the three systems is provided herein. The data from distribution supervisory control and data acquisition indicates the substation distribution feeder or line recloser status as well as other distribution line measurements on the distribution network. The geographical information provides the geo spatial line locations and routes as well as an electrical model of the distribution network. The outage management system provides the indication of line switch status. A distribution management system can provide many new analytic capabilities and a single operations view of the distribution network. By incorporating the information from all three systems into a single view the information can be visualized and create an electrical model of the distribution network. The electrical model of the distribution network is a real time model of the network based on the distribution supervisory control and data acquisition and outage management information combined. In addition to the electrical model from the geographical information a distribution management system can also create a state estimation for the distribution network. The state estimation utilizes measurement information from the network to provide an adjustments to the electrical model to tune it to match actual measurements. The model also provides electrical values for all line segments in the distribution network. This provides many of the operation and planning capabilities that the manufactures offer within a distribution management system.

TEP does not have a distribution supervisory control system. TEP utilizes an energy management system to indicate the status of the distribution substation feeder status. The PI data historian is utilized to store the status and measurement information from the distribution network. TEP does have a geographical system that contains the geo spatial information and electrical model of the distribution network. The geographical system information has been integrated into the outage management system to provide the outage management system electrical model. The system operators manually update the distribution line switch statuses to indicate distribution feeder circuits. The energy management system substation feeder breaker information has also been integrated into the outage management system to indicate feeder status. A separate integration has been created with geographical electrical model information to an electrical modeling and planning software for distribution planning activities. The information from the distribution network for the distribution planning activities is a static model based on the last model update and needs to be manually updated to indicate actual feeder configuration. Moving towards a distribution management system would create the system and benefits described above. The existing systems require manual processes and updates to keep updated and providing information.

RESPONDENT:

Jim Taylor

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.17

RE: Tilghman Direct at 7:2-18, with respect to the discussion of impacts of intermittent generation, for distributed generation (DG) resources not owned by the Company, please provide the following:

a. a list of each and every operational metric that TEP is concerned about with respect to DG with a definition of what it is and how TEP tracks the metric,

b. for each metric provided in response to part a) of this question please provide and any all data that TEP tracks with respect to the metric,

c. please explain how each metric identified in part a) of this question is the same or different depending on the various voltage levels that TEP operates (e.g. 500 kV, 345kV, 138kV, 46 kV, 13.8 kV, 4.16 kV, etc.),

d. any and all data that proves that intermittent generation from DG is creating greater load imbalance,

e. any and all data that proves that intermittent generation from DG is creating greater fluctuations in voltage,

f. any and all data that proves that intermittent generation from DG is creating greater fluctuation in frequency,

g. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater load imbalance together with any and all engineering studies that support the explanation and cost by month for the last ten years.

h. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuations in voltage together with any and all engineering studies that support the explanation and cost by month for the last ten years.

i. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuation of frequency together with any and all engineering studies that support the explanation and cost by month for the last ten years.

RESPONSE:

Please see the following files, as referenced below.

File Name	Bates Numbers
RUCO 3.17(a) NERC Glossary_of_Terms.pdf	TEP\020589-020706
RUCO 3.17(b) BAL-001-1.pdf	TEP\020707-020718
RUCO 3.17(b) BAL-001-2.pdf	TEP\020719-020727
RUCO 3.17(b) BAL-002-1.pdf	TEP\020728-020732
RUCO 3.17(b) BAL-002-WECC-2.pdf	TEP\020733-020744
RUCO 3.17(b) BAL-003-1.1.pdf	TEP\020745-020756
RUCO 3.17(d) 2015_Sample_Variability.xlsx	N/A

a. Below is a list of Balancing Authority ("BA") Area metrics that TEP is concerned about with respect to DG. Metrics are calculated and stored by the Energy Management System ("EMS") in company databases.

Area Control Error ("ACE")

Per the NERC Glossary of Terms (see RUCO 3.17(a) NERC Glossary_of_Terms.pdf), "The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction ("ATEC"), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection."

Frequency Response Measure ("FRM")

Per the NERC Glossary of Terms, "The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."

Frequency Response Obligation ("FRO")

Per the NERC Glossary of Terms, "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz."

Disturbance Control Standard ("DCS")

Per the NERC Glossary of Terms, "The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range."

Balancing Authority ACE Limit ("BAAL")

A Balancing Authority-specific limit on ACE derived from the BA's frequency bias, scheduled frequency, actual interconnection frequency, and epsilon, a targeted frequency bound defined by NERC for each interconnection. Also referred to as "Reliability-based Control," or RBC. BAs may not exceed either a BAAL High or BAAL Low for longer than 30 minutes. Definitions and calculations from BAL-001-2 (see file RUCO 3.17(b) BAL-002-1.pdf), which goes into effect on July 1, 2016. RBC has been in effect as a field trial in WECC since March 1, 2010, and WECC has monitored BA compliance with RBC since then.

Contingency Reserve ("CR")

Per the NERC Glossary of Terms, "The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard ("DCS") and other NERC and Regional Reliability Organization contingency requirements. The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements…."

b. TEP objects to this request as providing all data collected by TEP with regard to the metrics in part a) would be overly burdensome. However, without waiver of objection, the data collected for metric calculations are specified in various NERC and WECC documents and are listed below.

The ACE calculation is comprised of the components specified in RUCO 3.17(b) BAL-001-1.pdf.

Frequency Response Measure is comprised of the components in RUCO 3.17(b) BAL-003-1.1.pdf.

Frequency Response Obligation is comprised of the components in RUCO 3.17(b) BAL-003-1.1.pdf.

Compliance with the Disturbance Control Standard is calculated in accordance with RUCO 3.17(b) BAL-002-1.pdf.

Balancing Authority ACE Limits are comprised of the components RUCO 3.17(b) BAL-001-2.pdf.

Contingency Reserve is comprised of the components in RUCO 3.17(b) BAL-002-WECC-2.pdf.

Data is collected and calculations are performed by the EMS every 2 seconds.

c. Voltage level is not taken into consideration for any of the metrics listed in part a).

d. The TEP Balancing Authority considers DG variability in 10 minute increments. This is because reserves, both spinning and non-spinning, are calculated by what they can provide within 10 minutes. Please see RUCO 3.17(d) 2015_Sample_Variability.xlsx.

Ten-minute output values from different large-scale distributed solar sites connected to the TEP system can be summed and compared to show an aggregate 10-minute variability. At the BA level, there is no differentiation between TEP-owned and PPA DG sites; these sites are all metered into the TEP Balancing Authority at the transmission or distribution level and do not reside behind customer meters, so the effect on the BA Area is the same regardless of whether they are TEP-owned or PPAs.

Site	AC MW Capacity	Location	TEP Owned
Picture Rocks (aka FRV)	20	Marana, AZ	No, PPA
Avra Valley (aka NRG)	25	Marana, AZ	No, PPA
Fort Huachuca Phase I	13.6	Sierra Vista, AZ	Yes
U of A Tech Park (UASTP I & II)	5.3	Tucson, AZ	Yes
U of A Tech Park (Amonix, Cogenra, E.On Tech Park, Gato Montes Solar)	12	Tucson, AZ	No, PPA

These example sites comprise about 76 MW of AC rated capacity, and they reside in Southern Arizona within the TEP metered boundary. These are sites which TEP either owns or has PPAs with, meters directly to its EMS for the calculation of generation and load, and do not reside behind any customer meters.

When generation within a Balancing Authority fluctuates, it causes other generation on Automatic Generation Control to fluctuate, as well as the amount of interchange over BA Area ties. These changes also cause fluctuations in the BA ACE, making it more difficult to comply with relevant reliability standards like BAAL because changes can happen so rapidly and unpredictably.

The maximum positive 10-minute variability measured in the aggregated 2015 data is 26.4 MW or 34.73%, and the maximum negative 10-minute variability measured is -44.7 MW or -58.94%.

The DG sites used in this example, which are geographically diverse within Southern Arizona and the Tucson Valley, can exhibit large changes over short periods of time, even when aggregated. Applying this behavior to the entirety of the distributed solar in the Tucson Valley shows the potential for the Valley's aggregated solar to have serious impacts to the requirements of traditional generation, the BA Area interchange ties, BA ACE, and ability to maintain operating reserves. The negative variability coupled with normal system disturbances can deplete reserves making it difficult to maintain compliance with the metrics mentioned above.

Positioned behind customer meters, distributed generation will change the amount of power the customer draws. Small fluctuations in customer load are expected and normal, and even larger fluctuations exhibited by a few customer meters will be less obvious at a system level. However, when many customers utilize distributed solar generation, the aggregated impacts will increase to levels that will impact the overall system and metrics.

Other studies regarding distributed generation and customer load may be viewed on the SVERI Public Access Data Portal at sveri.uaren.org.

e. Results from interconnection studies routinely performed for distributed generation facilities indicate that large penetration levels of distributed generation resources can cause fluctuations in distribution system voltage. TEP cannot provide copies of these studies since they contain sensitive customer information and require the consent of the customer.

f. Any and all generation within an interconnected system has an effect on system frequency; therefore, any new generation introduced to a power system, including DG, will contribute to deviations in frequency.

Due to the relative size of DG versus total system generation capacity, frequency deviations specifically attributable to solar DG have not been measured within the TEP BA Area. However, as DG penetration becomes a larger percentage of overall generation, TEP expects the adverse effects of DG to become more visible and more easily attributable.

g. While variability of solar distributed generation has been observed, TEP has not calculated the direct costs as of yet.

h. While variability of solar distributed generation has been observed, TEP has not calculated the direct costs as of yet.

i. As previously stated, due to the relative size of DG versus total system generation capacity, frequency deviations specifically attributable to solar DG have not been measured within the TEP BA Area. However, as DG penetration becomes a larger percentage of overall generation, TEP expects the adverse effects of DG to become more visible and more easily attributable.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RESPONDENT:

Lauren Briggs / Ana Bustamante (e and h)

WITNESS:

Carmine Tilghman / Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.18

RE: Tilghman Direct at 7:2-18, with respect to the discussion of impacts of intermittent generation, for distributed generation (DG) resources owned by the Company, please provide the following:

a. a list of each and every operational metric that TEP is concerned about with respect to DG with a definition of what it is and how TEP tracks the metric,

b. for each metric provided in response to part a) of this question please provide any and all data that TEP tracks with respect to the metric,

c. please explain how each metric identified in part a) of this question is the same or different depending on the various voltage levels that TEP operates (e.g. 500 kV, 345kV, 138kV, 46 kV, 13.8 kV, 4.16 kV, etc.),

d. any and all data that proves that intermittent generation from DG is creating greater load imbalance,

e. any and all data that proves that intermittent generation from DG is creating greater fluctuations in voltage,

f. any and all data that proves that intermittent generation from DG is creating greater fluctuation in frequency,

g. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater load imbalance together with any and all engineering studies that support the explanation and cost by month for the last ten years.

h. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuations in voltage together with any and all engineering studies that support the explanation and cost by month for the last ten years.

i. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuation of frequency together with any and all engineering studies that support the explanation and cost by month for the last ten years.

RESPONSE:

Please see TEP's responses to RUCO 3.17.

RESPONDENT:

Lauren Brigs (a-d, f, g) / Engineering (e, h, i)

WITNESS:

Carmine Tilghman / Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.19

RE: Tilghman Direct at 8:4-27 through 9:1-2, please provide any and all engineering studies that TEP has performed that the excess energy from Distributed Generation resources not owned by TEP can result in increased

a. operations and maintenance costs,

b. equipment wear and tear,

c. energy flowing back up through the distribution system, and

d. during the shoulder months often results in reverse power flow and overload conditions.

RESPONSE:

a. TEP has not performed any engineering studies that specifically attribute an increase in operations and maintenance cost to Distributed Generation. However, on a regular basis TEP performs interconnection studies for large non-TEP owned distributed generation facilities which indicate that large penetration levels of distributed generation have impacts on system voltage during fluctuations of generation typically found with intermittent generation resources. During the intermittent generation periods, equipment upstream on the TEP distribution system are required to operate more frequently to compensate for the swings in system voltage. Maintenance costs for devices installed throughout the distribution system to control voltage, such as transformer load tap changers, line capacitors, and voltage regulators will increase as these devices are required to operate more frequently.

b. Distribution equipment will be required to operate more frequently as distributed generation penetration levels increase. As operation of these devices increase, wear and tear will increase, and additional maintenance will be required to maintain proper operation of the distribution system.

c. TEP performs feasibility studies as required by the company's Distributed Generation Interconnection Rules ("DGIRs") (https://www.tep.com/customer/construction/esr/). These studies generally include power flow simulations and voltage sag analysis, based upon assumptions of the customer's particular system characteristics as submitted in the interconnection application. TEP analyzes the voltage regulation issues arising from the intermittent solar availability, and based upon engineering analysis and calculations these reports can and do show energy flowing back into the distribution system as part of the engineering modeling. TEP is not able to provide these studies for non TEP owned facilities due to confidentiality constraints.

d. The same studies show an increase in reverse power to the grid during the light load case.

RESPONDENT:

Chis Lindsey

WITNESS:

Carmine Tilghman

STF 1.22

Renewable Resources: Please provide a narrative discussing how the Company has either implemented and/or researched the use of advanced inverters or other technologies to control PV generation at the source.

RESPONSE:

The Company is in the process of studying the impacts of implementing reactive power requirements to be provided by the inverters for Company-owned PV generation facilities. Advanced inverters have the ability to provide reactive power production day or night that may help support grid voltage where necessary.

The Company has constructed a test solar system with a Smart Inverter on the Irvington campus in Tucson with remote controls enabled. This system has been used to develop installation and communication standards and will allow for development of the new Smart Inverter control settings. The test system will be used to study the effects of time varying control settings versus active optimization control. Other control setting strategies will be investigated with the system as they are developed.

The Company has partnered with One Cycle Control ("OCC") to investigate their technologies that may support the integration of distributed generation. The OCC devices are small-scale dynamic VAR compensators that claim they can help control voltage at the distribution level more precisely and autonomously than other devices or technologies. This technology is planned for installation at an existing Company-owned PV facility by the end of the first quarter 2016.

The Company has been in collaboration with the University of Arizona at the Tech Park where a smart inverter and battery system are electrically tied to a solar field. The system has been used to assess the viability of controlling solar ramp rates, testing sensitivity of the grid to DG fluctuation and also using weather information to schedule curtailment to guaranty stable PV output on cloudy days.

The Company has identified the West Ina Substation as a preferred location for the installation of solar generation along with other supporting technologies. The goal of this project is to achieve increased energy delivery efficiency and system reinforcement cost avoidance for West Ina T1 and T2 thru installation and automation of distributed resources. There are 4 parts to achieving the goals of the project: the Residential Solar project, a central monitoring system, an autonomous decision application and a communication network. Engineering has been working on communication and control options to support these goals. The communication network is required to enable control of all DG resources.

RESPONDENT:

Carmine Tilghman / Chris Fleenor

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
February 2, 2016

STF 1.23

Renewable Resources: Please provide a narrative discussing how DG increases operating and maintenance costs and equipment wear and tear. [Tilghman 8:19]

RESPONSE:

In general, intermittent resources like solar DG are subject to fast and extreme changes in output. Conventional generation resources, which are used to follow the load and regulate frequency, are required to change their output more frequently and more quickly than before. More frequent operation at faster rates increases wear and tear on the equipment, and therefore maintenance costs.

In addition, the Company's operating and maintenance costs have increased related to interconnection facilities required for larger-scale DG. This includes the scheduled inspection and replacement of equipment required to support the proper integration and operations of larger DG facilities.

The idea that intermittent resources create additional challenges and service on the distribution grid is well documented throughout the industry. Whitepapers, presentations, and other forms of documentation are widely available from organizations such as National Renewable Engineering Laboratory ("NREL"), Massachusetts Institute of Technology ("MIT"), Lawrence Berkley Engineering Laboratory ("LBEL"), Solar Electric Power Association ("SEPA"), Southwest Variable Energy Resource Initiative's ("SVERI"), and others. Below is a partial list of publicly available documents from these entities covering a variety of issues associated variable generation.

1. Western Electricity Coordinating Council's Variable Generation Subcommittee Marketing Workgroup whitepaper – "Electricity Markets and Variable Generation Integration".
2. Western Electricity Coordinating Council's – "WECC Variable Generation Planning Reference Book: A Guidebook for Including Variable Generation in the Planning Process".
3. MIT Study on the Future of Solar Energy, specifically Chapter 7 – Integration of Distributed Photovoltaic Generators. https://mitei.mit.edu/futureofsolar
4. North American Electric Reliability Corporation (NERC) Special Report: Accommodating High Levels of Variable Generation, April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf
5. Western Wind and Solar Integration Study – "Analysis of Cycling Costs in Western Wind and Solar Integration Study". http://www.nrel.gov/docs/fy12osti/54864.pdf
6. NREL – "Fundamental Drivers of the Cost and Price of Operating Reserves". http://www.nrel.gov/docs/fy13osti/58491.pdf
7. Intertek APTECH report prepared for NREL and WECC – "Power Plant Cycling Costs"

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
February 2, 2016

STF 1.24

Renewable Resources: Please provide a narrative discussing how the Company has estimated or measured individual feeders subject to reverse powerflow and overload conditions. [Tilghman 8:21]

RESPONSE:

The Company meters and monitors the specific cases where reverse powerflow occurs at the feeder level to ensure operations are within industry tolerance and Company-owned facilities are operating within design parameters.

The Company also monitors the amount of distributed generation installed by feeder and conducts specific feeder studies if necessary to estimate potential reverse powerflow conditions. Specifically, a recent interconnection study has identified feeder conductor overloads due to the installation of customer-owned generation at the end of the feeder.

RESPONDENT:

Carmine Tilghman / Jim Taylor / Chris Fleenor / Chris Lindsey

WITNESS:

Carmine Tilghman

EXHIBIT FWR-21

Tucson Electric Power Company
Summary of Revenues by Customer Class
Present and Proposed Revenues
Test Year Ended June 30, 2015

Line No.	Rate Description	Test Year Net Revenue	Net Increase	Proposed % Increase to Test Year	Adjusted Test Year Revenue	Proposed Dollar Increase	Proposed % Increase to Adjusted Test Year	Proposed Net Revenue
1	Class Summary	$	$	%	$	$	%	$
2	Residential	414,763,081	1,583,498	0.4%	404,566,465	11,780,113	2.9%	416,346,578
3	General Service	263,662,971	(12,728,689)	-4.8%	249,088,907	1,845,375	0.7%	250,934,282
4	Large General Service	112,713,124	8,550,248	7.6%	119,203,655	2,059,717	1.7%	121,263,372
5	Large Power Service	136,020,579	(7,421,310)	-5.5%	127,759,401	733,028	0.7%	128,599,270
6	Transmission Service 138kV	0	0	n/a	0	0	n/a	0
7	Lighting	4,772,245	23,056	0.5%	4,654,992	140,309	3.0%	4,795,301
8	Subtotal	931,931,999	(9,993,197)	-1.1%	905,273,421	16,558,541	1.8%	921,938,803
9	Other Operating Revenue	$31,728,877		N/A	$31,728,877	N/A	N/A	$31,728,877
10	Total	$963,660,876	($9,993,197)	-1.0%	$937,002,298	$16,558,541	1.8%	$953,667,680

Supporting Schedules
H-2-2

Recap Schedules
A-1

Links
Other Operating Revenues - Revenue Requirement Model

Note:
-1 Test Year Billed Margin Revenues calculated $50,952 more than Booked Revenues.
-2 Test Year Billed Fuel and PPFAC revenues calculated $28,842 less than Booked Revenues.
-3 Total increase is $22,110 more than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues.
-4 Transmission Service 138kV is included with Large Power Service to conceal competitively sensitive confidential data.

Tucson Electric Power Company
Comparison of Sales by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	TEST YEAR UNADJUSTED			SALES ADJUSTMENTS	TEST YEAR ADJUSTED			PROPOSED		
Rate Description	Test Year Basic Service Charges	Test Year Sales (kWh)	Average Per Service Charge	kWh	Basic Service Charges	Adjusted Sales (kWh)	Average Per Service Charge	Basic Service Charges	Proposed Sales (kWh)	Average Per Service Charge
Class Summary										
Residential	4,618,963	3,675,966,286	796	(24,845,354)	4,624,515	3,651,120,932	790	4,624,515	3,651,120,932	790
General Service	461,846	2,133,735,714	4,620	(1,402,844)	462,775	2,132,332,869	4,608	460,877	1,839,512,456	3,991
Large General Service	7,013	1,189,053,400	169,550	(11,891,293)	6,931	1,177,162,108	169,835	8,865	1,477,690,240	166,682
Large Power Service	204	2,021,151,869	9,907,607	0	216	2,021,151,869	9,357,185	228	2,021,151,866	8,864,701
Transmission Service 138kV	0	0	0	0	0	0	0	0	0	0
Lighting	207,259	38,938,160	188	1,936	207,267	38,940,096	188	207,267	38,940,096	188
TOTAL COMPANY	5,295,285	9,058,845,428	1,711	(38,137,554)	5,301,705	9,020,707,874	1,701	5,301,753	9,028,415,591	1,703
<u>Residential Schedules</u>										
TE-R-01	4,179,070	3,280,964,594	785	(17,027,762)	4,184,314	3,263,936,831	780	4,184,314	3,263,936,831	780
TE-201A	138,080	130,588,706	946	(992,712)	138,058	129,595,994	939	138,058	129,595,994	939
TE-201B	7,903	8,666,134	1,097	(270,031)	7,755	8,396,104	1,083	7,755	8,396,104	1,083
TE-R80	98,375	110,682,540	1,125	(2,373,544)	96,994	108,308,996	1,117	96,994	108,308,996	1,117
TE-R8	754	579,737	769	643,017	1,368	1,222,754	894	1,368	1,222,754	894
TE-R01BC	13,711	11,172,024	815	231,296	14,020	11,403,320	813	14,020	11,403,320	813
<u>Lifeline Rate Schedules</u>										
TE4-01	6,104	3,418,618	560	(222,520)	5,794	3,196,098	552	5,794	3,196,098	552
TE4-21	36	34,185	950	(779)	36	33,406	928	36	33,406	928
TE4-70	72	59,862	831	(941)	72	58,921	818	72	58,921	818
TE5-01	14,084	9,286,821	659	(372,346)	13,698	8,914,475	651	13,698	8,914,475	651
TE5-21	22	25,179	1,145	(10,460)	13	14,719	1,132	13	14,719	1,132
TE5-70	138	94,379	684	(4,851)	134	89,528	669	134	89,528	669
TE6-01	84,662	61,762,560	730	(8,710,908)	74,767	53,051,652	710	74,767	53,051,652	710
TE6-21	228	262,501	1,151	(31,382)	208	231,119	1,112	208	231,119	1,112
TE6-70	839	782,644	933	(170,654)	683	611,990	896	683	611,990	896
TE6-201A	3,756	3,376,855	899	(386,675)	3,397	2,990,181	880	3,397	2,990,181	880
TE6-201B	63	46,930	745	(4,083)	60	42,848	714	60	42,848	714
TE8-01	8,307	8,093,719	974	(1,148,089)	7,336	6,945,630	947	7,336	6,945,630	947
TE8-21	84	124,764	1,485	(1,279)	84	123,485	1,470	84	123,485	1,470
TE8-70	225	223,584	994	(21,111)	211	202,473	958	211	202,473	958
TE8-201A	137	189,352	1,382	(39,071)	112	150,281	1,346	112	150,281	1,346
TE6-01BC	223	159,842	717	(22,220)	196	137,622	701	196	137,622	701
TE-R-01LL	59,739	39,538,976	662	9,350,601	72,257	48,889,577	677	72,257	48,889,577	677
TE-R01LB	149	123,563	829	15,799	166	139,362	838	166	139,362	838
TE-201AL	1,399	1,205,658	862	457,541	1,884	1,663,199	883	1,884	1,663,199	883
TE-201BL	20	27,399	1,370	30,026	40	57,425	1,454	40	57,425	1,454
TE-R80LL	767	625,652	816	76,511	846	702,163	830	846	702,163	830
TE-R8LL	16	11,669	729	(890)	13	10,779	808	13	10,779	808
Residential Unbilled		3,837,839								

Tucson Electric Power Company
Comparison of Sales by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	TEST YEAR UNADJUSTED			SALES ADJUSTMENTS	TEST YEAR ADJUSTED			PROPOSED		
Rate Description	Test Year Basic Service Charges	Test Year Sales (kWh)	Average Per Service Charge	kWh	Basic Service Charges	Adjusted Sales (kWh)	Average Per Service Charge	Basic Service Charges	Proposed Sales (kWh)	Average Per Service Charge
General Service										
TE-GS10	426,132	1,700,811,779	3,991	10,550,412	427,562	1,711,362,191	4,003	384,015	602,159,416	1,568
TE-GS11	3,580	48,768,661	13,623	(2,197,623)	3,451	46,571,038	13,495	3,451	46,571,038	13,495
TE-GS76	14,274	175,721,877	12,311	(2,109,763)	14,046	173,612,114	12,360	8,917	30,031,910	3,368
TE-G10BC	383	4,734,474	12,362	76,198	389	4,810,672	12,361	305	515,997	1,692
TE-GSM10	9,837	67,460,308	6,858	(827,799)	9,723	66,632,509	6,853	8,047	22,547,155	2,802
TE-G10MBC	526	27,240,424	51,788	(112,154)	524	27,128,270	51,785	0	0	0
TE-GS43	7,114	102,037,299	14,343	178,775	7,081	102,216,075	14,436	7,081	102,216,075	14,436
TE-MGS				0				43,456	889,460,744	
TE-MGSTOU				0				5,160	130,716,715	
TE-MGSBC								446	15,293,406	
General Service Unbilled		6,960,891								
Large General Service										
TE-LGS13	5,312	859,436,643	161,792	(4,638,491)	5,279	854,798,152	161,915	7,046	1,118,625,537	158,770
TE-LG85	1,606	310,229,617	193,169	(9,593,839)	1,556	300,635,778	193,249	1,561	321,206,987	205,790
TE-L13BC	95	21,576,660	227,123	151,518	96	21,728,178	225,812	259	37,857,717	146,221
Large General Service Unbilled		(2,189,520)								
Large Power Service										
TE-LLP14	26	139,880,570	5,380,022	(5,790,325)	24	134,090,245	5,587,094	0	0	0
Special	0	28,794,874	2,399,573	(28,794,874)	0	0	0	0	0	0
Large Power Service TOU	178	1,854,388,905	10,417,915	32,672,719	192	1,887,061,624	9,828,446	228	2,021,151,866	8,864,701
Large Power Service Unbilled		-1,912,480								
Transmission Service 138kV										
TE-T138kV	0	0	0	N/A	0	0	0	0	0	#DIV/0!
Lighting										
TE-P41	9,104	22,615,813	2,484	207,661	9,096	22,823,474	2,509	9,096	22,823,474	2,509
TE-P47	6,758	8,545,881	1,265	102,017	6,774	8,647,898	1,277	6,774	8,647,898	1,277
TE-R51 + TE-R51A	17,636	672,153	38	(3,839)	17,636	668,314	38	17,636	668,314	38
TE-C52 & 52A	135,544	4,930,591	36	(3,891)	135,544	4,926,700	36	135,544	4,926,700	36
TE-P50	38,217	1,852,451	48	21,259	38,217	1,873,710	49	38,217	1,873,710	49
Lighting Unbilled		321,271								

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Rate Description	Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue Plus Fuel Proforma		Proposed Revenues		Proposed Increase to Test Year Revenue		Proposed Increase to Adjusted Revenue	
	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
Class Summary											
Residential	277,207,565	137,555,516	(10,196,615)	275,887,975	128,678,490	287,668,088	128,678,490	1,583,498	0.38%	11,780,113	2.9%
General Service	184,360,130	79,302,841	(14,574,064)	184,448,887	64,640,020	186,294,262	64,640,020	(12,728,689)	-4.83%	1,845,375	0.7%
Large General Service	68,297,227	44,415,897	6,490,532	68,460,569	50,743,086	70,520,286	50,743,086	8,550,248	7.59%	2,059,717	1.7%
Large Power Service	73,191,548	62,829,031	(8,261,178)	73,302,768	54,456,633	74,032,047	59,042,925	(2,945,607)	-2.17%	5,315,572	4.2%
Transmission Service Rate	0	0	0	0	0	0	0	0	N/A	0	N/A
Lighting	3,303,187	1,469,057	(117,253)	3,298,783	1,356,208	3,439,093	1,356,208	23,056	0.48%	140,309	3.0%
TOTAL COMPANY	606,359,658	325,572,341	(26,658,579)	605,398,982	299,874,438	621,953,775	304,460,731	(5,517,494)	-0.59%	21,141,085	2.3%
<u>Residential Schedules</u>											
TE-R-01	251,807,725	122,674,283	(6,715,851)	250,967,738	116,798,419	261,977,935	116,798,419	4,294,346	1.15%	11,010,197	2.99%
TE-201A	8,979,804	4,880,819	(1,014,765)	8,923,159	3,922,699	9,322,984	3,922,699	(614,940)	-4.44%	399,825	3.11%
TE-201B	462,115	298,135	(79,283)	449,399	231,569	468,742	231,569	(59,939)	-7.88%	19,343	2.84%
TE-R80	6,748,591	3,807,714	(430,112)	6,629,150	3,497,044	6,925,163	3,497,044	(134,099)	-1.27%	296,013	2.92%
TE-R8	39,021	17,725	68,302	84,240	40,808	87,918	40,808	71,980	126.85%	3,678	2.94%
TE-R01BC	851,640	373,656	17,298	870,889	371,706	909,362	371,706	55,771	4.55%	38,473	3.10%
<u>Lifeline Rate Schedules</u>											
TE4-01	187,990	89,256	(23,299)	175,417	78,529	158,537	78,529	(40,179)	-14.49%	(16,881)	-6.65%
TE4-21	1,612	1,028	(57)	1,567	1,016	1,537	1,016	(87)	-3.28%	(30)	-1.16%
TE4-70	3,139	1,644	(76)	3,077	1,629	3,161	1,629	8	0.16%	84	1.79%
TE5-01	571,226	277,370	(46,143)	547,423	255,030	507,429	255,030	(86,138)	-10.15%	(39,994)	-4.98%
TE5-21	1,242	807	(856)	738	455	677	455	(917)	-44.77%	(61)	-5.11%
TE5-70	5,466	2,786	(786)	5,162	2,304	4,604	2,304	(1,344)	-16.28%	(558)	-7.47%
TE6-01	3,730,879	1,828,957	(803,104)	3,203,498	1,553,234	3,047,830	1,553,234	(958,772)	-17.24%	(155,668)	-3.27%
TE6-21	12,269	7,969	(2,560)	10,790	6,887	10,304	6,887	(3,046)	-15.05%	(486)	-2.75%
TE6-70	43,687	23,012	(15,364)	34,101	17,235	32,696	17,235	(16,768)	-25.14%	(1,405)	-2.74%
TE6-201A	169,675	102,562	(47,539)	149,713	74,985	150,517	74,985	(46,736)	-17.17%	803	0.36%
TE6-201B	2,038	1,298	(551)	1,840	945	1,907	945	(483)	-14.49%	68	2.44%
TE8-01	386,096	196,771	(49,567)	329,967	203,333	382,282	203,333	2,749	0.47%	52,315	9.81%
TE8-21	4,771	3,238	613	4,722	3,898	5,664	3,898	1,555	19.41%	942	10.93%
TE8-70	9,942	5,317	(670)	8,887	5,702	10,732	5,702	1,174	7.69%	1,844	12.64%
TE8-201A	7,659	4,895	(2,503)	6,028	4,023	7,659	4,023	(872)	-6.95%	1,631	16.22%
TE6-01BC	9,626	4,699	(2,038)	8,290	3,997	7,873	3,997	(2,455)	-17.14%	(417)	-3.39%
TE-R-01LL	2,674,986	1,311,018	862,874	3,316,275	1,532,603	3,479,033	1,532,603	1,025,632	25.73%	162,758	3.36%
TE-R01LB	8,347	4,190	1,367	9,438	4,466	9,909	4,466	1,838	14.66%	471	3.39%
TE-201AL	74,180	40,970	31,728	102,638	44,240	107,724	44,240	36,814	31.97%	5,086	3.46%
TE-201BL	1,323	877	1,975	2,746	1,429	2,881	1,429	2,110	95.90%	135	3.22%
TE-R80LL	35,808	19,187	5,372	40,408	19,959	42,321	19,959	7,285	13.25%	1,913	3.17%
TE-R8LL	707	334	(21)	674	346	707	346	11	1.10%	32	3.18%
Residential Unbilled	376,000	1,575,000		Unbilled is included above		0	0	0	N/A	0	N/A

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue Plus Fuel Proforma		Proposed Revenues		Proposed Increase to Test Year Revenue		Proposed Increase to Adjusted Revenue	
Rate Description	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
General Service											
TE-GS10	153,865,268	63,703,857	(41,177,457)	155,070,441	21,321,226	67,938,091	21,321,226	(128,309,807)	-58.97%	(87,132,351)	-49.40%
TE-GS11	3,524,955	1,819,452	(325,112)	3,367,260	1,652,035	4,113,888	1,652,035	421,515	7.89%	746,628	14.88%
TE-GS76	13,847,635	6,008,984	(5,202,103)	13,712,568	941,948	3,259,956	941,948	(15,654,715)	-78.84%	(10,452,612)	-71.33%
TE-G10BC	420,954	145,939	(30,523)	427,972	108,399	57,591	108,399	(400,903)	-70.72%	(370,380)	-69.05%
TE-GSM10	5,066,210	2,108,192	(1,371,308)	5,004,641	798,454	2,485,321	798,454	(3,890,628)	-54.23%	(2,519,320)	-43.41%
TE-G10MBC	2,009,095	821,670	(454,729)	1,998,695	377,341	0	377,341	(2,453,424)	-86.67%	(1,998,695)	-84.12%
TE-GS43	4,858,013	3,651,746	(184,699)	4,867,310	3,457,751	6,197,742	3,457,751	1,145,734	13.46%	1,330,433	15.98%
TE-MGS	0	0	31,610,660	0	31,610,660	88,099,007	31,610,660	119,709,667	N/A	88,099,007	N/A
TE-MGSTOU	0	0	4,121,991	0	4,121,991	12,634,344	4,121,991	16,756,335	N/A	12,634,344	N/A
TE-MGSBC					250,216	1,508,321	250,216	1,758,537	N/A	1,508,321	N/A
General Service Unbilled	768,000	1,043,000		Unbilled is included above		0	0	0	N/A	0	N/A
Large General Service											
TE-LGS13	52,178,293	32,183,205	7,235,419	51,915,256	39,681,660	55,346,315	39,681,660	10,666,477	12.64%	3,431,058	3.75%
TE-LG85	15,878,358	10,579,443	(995,745)	15,386,190	10,075,866	13,330,654	10,075,866	(3,051,281)	-11.53%	(2,055,535)	-8.07%
TE-L13BC	1,151,576	720,248	272,859	1,159,123	985,560	1,843,317	985,560	957,052	51.13%	684,194	31.90%
Large General Service Unbilled	-911,000	933,000		Unbilled is included above		0	0	0	N/A	0	N/A
Large Power Service											
TE-LLP14	6,004,077	4,773,275	(9,605,725)	5,757,919	-4,586,292	0	0	0	0	N/A	N/A
Special	882,693	777,092	(1,659,785)	0	0	0	0	0	0	N/A	N/A
Large Power Service TOU	66,309,779	57,243,663	3,034,332	67,544,848	59,042,925	74,032,047	59,042,925	9,521,530	7.71%	6,487,199	5.12%
Industrial Unbilled	-5,000	35,000		Unbilled is included above		0	0	0	N/A	0	N/A
Transmission Service 138kV											
TE-T138kV	0	0	0	0	0	0	0	0	N/A	0	N/A
Lighting											
TE-P41	1,076,513	846,600	(35,111)	1,086,397	801,604	1,132,569	801,604	11,060	0.58%	46,172	2.45%
TE-P47	406,784	319,997	(11,146)	411,640	303,995	429,135	303,995	6,349	0.87%	17,495	2.44%
TE-R51 + TE-R51A	145,242	25,118	(2,571)	145,228	22,560	151,401	22,560	3,602	2.11%	6,173	3.68%
TE-C52 & 52A	1,293,110	184,528	(21,022)	1,290,979	165,636	1,345,956	165,636	33,955	2.30%	54,977	3.77%
TE-P50	364,539	69,816	(7,403)	364,539	62,413	380,032	62,413	8,090	1.86%	15,493	3.63%
Lighting Unbilled	17,000	23,000		Unbilled is included above		0	0	0	N/A	0	N/A

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5000	TE-R-01	**Residential Service**				
		Basic Service Charge Single Phase Per Mo.	$10.00	$10.00	$0.00	0%
		Basic Service Charge Three Phase Per Mo.	$15.00	$15.00	$0.00	0%
		Sum First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Sum 501-1,000 kWh	$0.067200	$0.070807	$0.003607	5%
		Sum 1,001-3,500 kWh	$0.079800	$0.084084	$0.004284	5%
		Sum>3,500 kWh	$0.088200	$0.084084	-$0.004116	-5%
		Win First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Win 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win 1,001-3,500 kWh	$0.078100	$0.082292	$0.004192	5%
		Win>3,500 kWh	$0.087100	$0.082292	-$0.004808	-6%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
		Solar Block Rate for Residential Electric Service Rate R-01	$0.053463	$0.055785	$0.002322	4%
XXXX	TE-RXXX	**Residential Service Demand**				
		Basic Service Charge Per Month	N/M	$20.00	N/M	N/M
		Demand 0-7 kW	N/M	$7.40	N/M	N/M
		Demand > 7 kW	N/M	$11.90	N/M	N/M
		Sum kWh	N/M	$0.025000	N/M	N/M
		Win kWh	N/M	$0.025000	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5004	TE-201A	**Special Residential Electric Service**				
		Basic Service Charge	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.050600	$0.053316	$0.002716	5%
		Sum 501-1,000 kWh	$0.060500	$0.063748	$0.003248	5%
		Sum 1,001-3,500 kWh	$0.071800	$0.075654	$0.003854	5%
		Sum>3,500 kWh	$0.079400	$0.075654	-$0.003746	-5%
		Win First 500 kWh	$0.050600	$0.053316	$0.002716	5%
		Win 501-1,000 kWh	$0.058700	$0.061851	$0.003151	5%
		Win 1,001-3,500 kWh	$0.070300	$0.074074	$0.003774	5%
		Win>3,500 kWh	$0.078400	$0.074074	-$0.004326	-6%
		Base Power Summer kWh	$0.035111	$0.031726	-$0.003385	-10%
		Base Power Winter kWh	$0.031532	$0.028731	-$0.002801	-9%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5005	TE-201B	**Special Residential Electric Service Time of Use**				
		Basic Service Charge	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak 501-1,000 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak1,001-3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak >3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum Off-peak First 500 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak 501-1,000 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak1,001-3,500 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak >3,500 kWh	$0.044000	$0.046362	$0.002362	5%
		Win On-peak First 500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak 501-1,000 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak1,001-3,500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak >3,500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win Off-peak First 500 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak 501-1,000 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak1,001-3,500 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak >3,500 kWh	$0.035500	$0.037406	$0.001906	5%
		Base Power Summer On-Peak kWh	$0.050669	$0.051680	$0.001011	2%
		Base Power Summer Off-Peak kWh	$0.026679	$0.021845	-$0.004834	-18%
		Base Power Winter On-peak kWh	$0.032893	$0.047600	$0.014707	45%
		Base Power Winter Off-peak kWh	$0.027092	$0.018785	-$0.008307	-31%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5040	TE-R80	**Residential Time of Use**				
		Basic Service Charge	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak 501-1,000 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak1,001-3,500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak >3,500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum Off-peak First 500 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak 501-1,000 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak1,001-3,500 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak >3,500 kWh	$0.051800	$0.054581	$0.002781	5%
		Win On-peak First 500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak 501-1,000 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak1,001-3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak >3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win Off-peak First 500 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak 501-1,000 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak1,001-3,500 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak >3,500 kWh	$0.041800	$0.044044	$0.002244	5%
		Base Power Summer On-Peak kWh	$0.050669	$0.060800	$0.010131	20%
		Base Power Summer Off-Peak kWh	$0.026679	$0.025700	-$0.000979	-4%
		Base Power Winter On-peak kWh	$0.032893	$0.056000	$0.023107	70%
		Base Power Winter Off-peak kWh	$0.027092	$0.022100	-$0.004992	-18%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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XXXX	TE-RXXX	**Residential Demand Time of Use**				
		Basic Service Charge Per Month	N/M	$20.00	N/M	N/M
		Demand 0-7 kW	N/M	$7.40	N/M	N/M
		Demand > 7 kW	N/M	$11.90	N/M	N/M
		Sum On-peak kWh	N/M	$0.025000	N/M	N/M
		Sum Off-peak kWh	N/M	$0.025000	N/M	N/M
		Win On-peak kWh	N/M	$0.025000	N/M	N/M
		Win Off-peak kWh	N/M	$0.025000	N/M	N/M
		Base Power Summer On-Peak kWh	N/M	$0.060800	N/M	N/M
		Base Power Summer Off-Peak kWh	N/M	$0.025700	N/M	N/M
		Base Power Winter On-peak kWh	N/M	$0.056000	N/M	N/M
		Base Power Winter Off-peak kWh	N/M	$0.022100	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5042	TE-R8	**Residential Time of Use Super Peak**				
		Basic Service Charge	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.097100	$0.102312	$0.005212	5%
		Sum On-peak 501-1,000 kWh	$0.097100	$0.102312	$0.005212	5%
		Sum On-peak1,001-3,500 kWh	$0.120100	$0.126547	$0.006447	5%
		Sum On-peak >3,500 kWh	$0.120100	$0.126547	$0.006447	5%
		Sum Off-peak First 500 kWh	$0.048500	$0.051103	$0.002603	5%
		Sum Off-peak 501-1,000 kWh	$0.048500	$0.051103	$0.002603	5%
		Sum Off-peak1,001-3,500 kWh	$0.071500	$0.075338	$0.003838	5%
		Sum Off-peak >3,500 kWh	$0.071500	$0.075338	$0.003838	5%
		Win On-peak First 500 kWh	$0.089100	$0.093883	$0.004783	5%
		Win On-peak 501-1,000 kWh	$0.089100	$0.093883	$0.004783	5%
		Win On-peak1,001-3,500 kWh	$0.112100	$0.118118	$0.006018	5%
		Win On-peak >3,500 kWh	$0.112100	$0.118118	$0.006018	5%
		Win Off-peak First 500 kWh	$0.038500	$0.040567	$0.002067	5%
		Win Off-peak 501-1,000 kWh	$0.038500	$0.040567	$0.002067	5%
		Win Off-peak1,001-3,500 kWh	$0.061500	$0.064801	$0.003301	5%
		Win Off-peak >3,500 kWh	$0.061500	$0.064801	$0.003301	5%
		Base Power Summer On-Peak kWh	$0.080100	$0.082900	$0.002800	3%
		Base Power Summer Off-Peak kWh	$0.022200	$0.027700	$0.005500	25%
		Base Power Winter On-peak kWh	$0.040200	$0.082900	$0.042700	106%
		Base Power Winter Off-peak kWh	$0.020500	$0.024100	$0.003600	18%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5060	TE-R01BC	**Residential Service R-01 Bright Community Solar**				
		Basic Service Charge Single Phase	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Sum 501-1,000 kWh	$0.067200	$0.070807	$0.003607	5%
		Sum 1,001-3,500 kWh	$0.079800	$0.084084	$0.004284	5%
		Sum>3,500 kWh	$0.088200	$0.084084	-$0.004116	-5%
		Win First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Win 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win 1,001-3,500 kWh	$0.078100	$0.082292	$0.004192	5%
		Win>3,500 kWh	$0.087100	$0.082292	-$0.004808	-6%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5002	TE4-01	**Lifeline Residential Service Standard (Frozen 1996 - R-04-01F Senior % Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5008	TE4-21	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
		Basic Service Charge Per Month	$8.86	$8.86	$0.00	0%
		Sum On-Peak First 500 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak 501-1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak >1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum Off-Peak First 500 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak 501-1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak >1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak 501-1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak >1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Base Power Summer On-Peak kWh	$0.053198	$0.060800	$0.007602	14%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5009	TE4-70	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Sum On-Peak First 500 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak 501-1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak >1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum Shldr-Peak First 500 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak >1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Off-Peak First 500 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak 501-1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak >1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Win On-Peak First 500 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak 501-1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak >1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win Off-Peak First 500 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak 501-1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak >1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Base Power Summer On-Peak kWh	$0.055698	$0.060800	$0.005102	9%
		Base Power Summer Shoulder kWh	$0.048198	$0.060800	$0.012602	26%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5010	TE5-01	**Lifeline Residential Service Standard (Frozen Lifeline % Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5012	TE5-21	**Residential Time of Use (Frozen Lifeline % Discount)**				
		Basic Service Charge Per Month	$8.86	$8.86	$0.00	0%
		Sum On-Peak First 500 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak 501-1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak >1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum Off-Peak First 500 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak 501-1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak >1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak 501-1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak >1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Base Power Summer On-Peak kWh	$0.053198	$0.060800	$0.007602	14%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5013	TE5-70	**Residential Time of Use (Frozen Lifeline % Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Sum On-Peak First 500 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak 501-1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak >1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum Shldr-Peak First 500 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak >1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Off-Peak First 500 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak 501-1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak >1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Win On-Peak First 500 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak 501-1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak >1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win Off-Peak First 500 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak 501-1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak >1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Base Power Summer On-Peak kWh	$0.055698	$0.060800	$0.005102	9%
		Base Power Summer Shoulder kWh	$0.048198	$0.060800	$0.012602	26%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

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5016	TE6-01	**Residential Service Standard (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5017	TE6-21	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$8.86	$8.86	$0.00	0%
		Sum On-Peak First 500 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak 501-1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak >1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum Off-Peak First 500 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak 501-1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak >1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak 501-1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak >1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Base Power Summer On-Peak kWh	$0.053198	$0.060800	$0.007602	14%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5022	TE6-70	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Sum On-Peak First 500 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak 501-1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak >1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum Shldr-Peak First 500 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak >1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Off-Peak First 500 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak 501-1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak >1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Win On-Peak First 500 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak 501-1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak >1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win Off-Peak First 500 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak 501-1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak >1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Base Power Summer On-Peak kWh	$0.055698	$0.060800	$0.005102	9%
		Base Power Summer Shoulder kWh	$0.048198	$0.060800	$0.012602	26%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5023	TE6-201A	**Special Residential Service (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Mid Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Mid Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Mid Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Remain Sum First 500 kWh	$0.043600	$0.045940	$0.002340	5%
		Remain Sum 501-1,000 kWh	$0.043600	$0.045940	$0.002340	5%
		Remain Sum >1,000 kWh	$0.043600	$0.045940	$0.002340	5%
		Win First 500 kWh	$0.041300	$0.043517	$0.002217	5%
		Win 501-1,000 kWh	$0.041300	$0.043517	$0.002217	5%
		Win >1,000 kWh	$0.041300	$0.043517	$0.002217	5%
		Base Power Mid Summer kWh	$0.033198	$0.031726	-$0.001472	-4%
		Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
		Base Power Winter kWh	$0.027198	$0.028731	$0.001533	6%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5024	TE6-201B	**Special Residential Service Time of Use (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Mid Sum On-Peak First 500 kWh	$0.136900	$0.144249	$0.007349	5%
		Mid Sum On-Peak 501-1,000 kWh	$0.136900	$0.144249	$0.007349	5%
		Mid Sum On-Peak >1,000 kWh	$0.136900	$0.144249	$0.007349	5%
		Mid Sum Shlder-Peak First 500 kWh	$0.074700	$0.078710	$0.004010	5%
		Mid Sum Shldr-Peak 501-1,000 kWh	$0.074700	$0.078710	$0.004010	5%
		Mid Sum Shldr-Peak >1,000 kWh	$0.074700	$0.078710	$0.004010	5%
		Mid Sum Off-Peak First 500 kWh	$0.038300	$0.040356	$0.002056	5%
		Mid Sum Off-Peak 501-1,000 kWh	$0.038300	$0.040356	$0.002056	5%
		Mid Sum Off-Peak >1,000 kWh	$0.038300	$0.040356	$0.002056	5%
		Remain Sum On-Peak First 500 kWh	$0.099500	$0.104841	$0.005341	5%
		Remain Sum On-Peak 501-1,000 kWh	$0.099500	$0.104841	$0.005341	5%
		Remain Sum On-Peak >1,000 kWh	$0.099500	$0.104841	$0.005341	5%
		Remain Sum Shlder-Peak First 500 kWh	$0.048600	$0.051209	$0.002609	5%
		Remain Sum Shldr-Peak 501-1,000 kWh	$0.048600	$0.051209	$0.002609	5%
		Remain Sum Shldr-Peak >1,000 kWh	$0.048600	$0.051209	$0.002609	5%
		Remain Sum Off-Peak First 500 kWh	$0.025300	$0.026658	$0.001358	5%
		Remain Sum Off-Peak 501-1,000 kWh	$0.025300	$0.026658	$0.001358	5%
		Remain Sum Off-Peak >1,000 kWh	$0.025300	$0.026658	$0.001358	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.015300	$0.016121	$0.000821	5%
		Win Off-Peak 501-1,000 kWh	$0.015300	$0.016121	$0.000821	5%
		Win Off-Peak >1,000 kWh	$0.015300	$0.016121	$0.000821	5%
		Base Power Mid Summer On-Peak kWh	$0.055698	$0.054723	-$0.000975	-2%
		Base Power Mid Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
		Base Power Mid Summer Off-Peak kWh	$0.023198	$0.021845	-$0.001353	-6%
		Base Power Remaining Summer On-Peak kWh	$0.055698	$0.000000	-$0.055698	-100%
		Base Power Remaining Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
		Base Power Remaining Summer Off-Peak kWh	$0.023198	$0.000000	-$0.023198	-100%
		Base Power Winter On-Peak kWh	$0.040698	$0.047600	$0.006902	17%
		Base Power Winter Off-Peak kWh	$0.020698	$0.018785	-$0.001913	-9%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5026	TE8-01	**Residential Service Standard (Frozen Lifeline Medical % Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5027	TE8-21	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
		Basic Service Charge Per Month	$8.86	$8.86	$0.00	0%
		Sum On-Peak First 500 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak 501-1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak >1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum Off-Peak First 500 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak 501-1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak >1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak 501-1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak >1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Base Power Summer On-Peak kWh	$0.053198	$0.060800	$0.007602	14%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5028	TE8-70	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Sum On-Peak First 500 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak 501-1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak >1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum Shldr-Peak First 500 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak >1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Off-Peak First 500 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak 501-1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak >1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Win On-Peak First 500 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak 501-1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak >1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win Off-Peak First 500 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak 501-1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak >1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Base Power Summer On-Peak kWh	$0.055698	$0.060800	$0.005102	9%
		Base Power Summer Shoulder kWh	$0.048198	$0.060800	$0.012602	26%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5029	TE8-201A	**Special Residential Service (Frozen Lifeline Medical % Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Mid Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Mid Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Mid Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Remain Sum First 500 kWh	$0.043600	$0.045940	$0.002340	5%
		Remain Sum 501-1,000 kWh	$0.043600	$0.045940	$0.002340	5%
		Remain Sum >1,000 kWh	$0.043600	$0.045940	$0.002340	5%
		Win First 500 kWh	$0.041300	$0.043517	$0.002217	5%
		Win 501-1,000 kWh	$0.041300	$0.043517	$0.002217	5%
		Win >1,000 kWh	$0.041300	$0.043517	$0.002217	5%
		Base Power Mid Summer kWh	$0.033198	$0.031726	-$0.001472	-4%
		Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
		Base Power Winter kWh	$0.027198	$0.028731	$0.001533	6%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5032	TE6-01BC	**Residential Service Standard (Frozen Lifeline Flat Discount) Bright Community Solar**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5033	TE-R-01LL	**Residential Service Standard**				
		Basic Service Charge Per Month	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Sum 501-1,000 kWh	$0.067200	$0.070807	$0.003607	5%
		Sum 1,001-3,500 kWh	$0.079800	$0.084084	$0.004284	5%
		Sum>3,500 kWh	$0.088200	$0.092935	$0.004735	5%
		Win First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Win 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win 1,001-3,500 kWh	$0.078100	$0.082292	$0.004192	5%
		Win>3,500 kWh	$0.087100	$0.091776	$0.004676	5%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5034	TE-R01LB	**Residential Service R-01 Bright Community Solar**				
		Basic Service Charge Per Month	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Sum 501-1,000 kWh	$0.067200	$0.070807	$0.003607	5%
		Sum 1,001-3,500 kWh	$0.079800	$0.084084	$0.004284	5%
		Sum>3,500 kWh	$0.088200	$0.092935	$0.004735	5%
		Win First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Win 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win 1,001-3,500 kWh	$0.078100	$0.082292	$0.004192	5%
		Win>3,500 kWh	$0.087100	$0.091776	$0.004676	5%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5035	TE-201AL	**Special Residential Electric Service**				
		Basic Service Charge Per Month	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.050600	$0.053316	$0.002716	5%
		Sum 501-1,000 kWh	$0.060500	$0.063748	$0.003248	5%
		Sum 1,001-3,500 kWh	$0.071800	$0.075654	$0.003854	5%
		Sum>3,500 kWh	$0.079400	$0.083662	$0.004262	5%
		Win First 500 kWh	$0.050600	$0.053316	$0.002716	5%
		Win 501-1,000 kWh	$0.058700	$0.061851	$0.003151	5%
		Win 1,001-3,500 kWh	$0.070300	$0.074074	$0.003774	5%
		Win>3,500 kWh	$0.078400	$0.082609	$0.004209	5%
		Base Power Summer kWh	$0.035111	$0.031726	-$0.003385	-10%
		Base Power Winter kWh	$0.031532	$0.028731	-$0.002801	-9%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5036	TE-201BL	**Residential Time of Use**				
		Basic Service Charge Per Month	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak 501-1,000 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak1,001-3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak >3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum Off-peak First 500 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak 501-1,000 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak1,001-3,500 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak >3,500 kWh	$0.044000	$0.046362	$0.002362	5%
		Win On-peak First 500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak 501-1,000 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak1,001-3,500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak >3,500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win Off-peak First 500 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak 501-1,000 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak1,001-3,500 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak >3,500 kWh	$0.035500	$0.037406	$0.001906	5%
		Base Power Summer On-Peak kWh	$0.050669	$0.051680	$0.001011	2%
		Base Power Summer Off-Peak kWh	$0.026679	$0.021845	-$0.004834	-18%
		Base Power Winter On-peak kWh	$0.032893	$0.047600	$0.014707	45%
		Base Power Winter Off-peak kWh	$0.027092	$0.018785	-$0.008307	-31%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5041	TE-R80LL	**Residential Time of Use**				
		Basic Service Charge Per Month	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak 501-1,000 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak1,001-3,500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak >3,500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum Off-peak First 500 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak 501-1,000 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak1,001-3,500 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak >3,500 kWh	$0.051800	$0.054581	$0.002781	5%
		Win On-peak First 500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak 501-1,000 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak1,001-3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak >3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win Off-peak First 500 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak 501-1,000 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak1,001-3,500 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak >3,500 kWh	$0.041800	$0.044044	$0.002244	5%
		Base Power Summer On-Peak kWh	$0.050669	$0.060800	$0.010131	20%
		Base Power Summer Off-Peak kWh	$0.026679	$0.025700	-$0.000979	-4%
		Base Power Winter On-peak kWh	$0.032893	$0.056000	$0.023107	70%
		Base Power Winter Off-peak kWh	$0.027092	$0.022100	-$0.004992	-18%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5043	TE-R8LL	**Residential Time of Use Super Peak Lifeline**				
		Basic Service Charge Per Month	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.097100	$0.102312	$0.005212	5%
		Sum On-peak 501-1,000 kWh	$0.097100	$0.102312	$0.005212	5%
		Sum On-peak1,001-3,500 kWh	$0.120100	$0.126547	$0.006447	5%
		Sum On-peak >3,500 kWh	$0.120100	$0.126547	$0.006447	5%
		Sum Off-peak First 500 kWh	$0.048500	$0.051103	$0.002603	5%
		Sum Off-peak 501-1,000 kWh	$0.048500	$0.051103	$0.002603	5%
		Sum Off-peak1,001-3,500 kWh	$0.071500	$0.075338	$0.003838	5%
		Sum Off-peak >3,500 kWh	$0.071500	$0.075338	$0.003838	5%
		Win On-peak First 500 kWh	$0.089100	$0.093883	$0.004783	5%
		Win On-peak 501-1,000 kWh	$0.089100	$0.093883	$0.004783	5%
		Win On-peak1,001-3,500 kWh	$0.112100	$0.118118	$0.006018	5%
		Win On-peak >3,500 kWh	$0.112100	$0.118118	$0.006018	5%
		Win Off-peak First 500 kWh	$0.038500	$0.040567	$0.002067	5%
		Win Off-peak 501-1,000 kWh	$0.038500	$0.040567	$0.002067	5%
		Win Off-peak1,001-3,500 kWh	$0.061500	$0.064801	$0.003301	5%
		Win Off-peak >3,500 kWh	$0.061500	$0.064801	$0.003301	5%
		Base Power Summer On-Peak kWh	$0.080100	$0.082900	$0.002800	3%
		Base Power Summer Off-Peak kWh	$0.022200	$0.027700	$0.005500	25%
		Base Power Winter On-peak kWh	$0.040200	$0.082900	$0.042700	106%
		Base Power Winter Off-peak kWh	$0.020500	$0.024100	$0.003600	18%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

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XXXX	TE-PESXX	**Prepay Electric Service**				
		Basic Service Charge Per Day	N/M	$0.84	N/M	N/M
		Sum First 20 kWh Per Day	N/M	$0.064000	N/M	N/M
		Sum >20 kWh Per Day	N/M	$0.079000	N/M	N/M
		Win First 20 kWh Per Day	N/M	$0.064000	N/M	N/M
		Win >20 kWh Per Day	N/M	$0.079000	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5200	TE-GS10	**Small General Service**				
		Basic Service Charge Single Phase Per Mo.	$15.50	$15.50	$0.00	0%
		Basic Service Charge Three Phase Per Mo.	$20.50	$20.50	$0.00	0%
		Sum First 500 kWh	$0.077000	$0.094095	$0.017095	22%
		Sum >500 kWh	$0.097800	$0.119550	$0.021750	22%
		Win First 500 kWh	$0.057000	$0.069747	$0.012747	22%
		Win >500 kWh	$0.079000	$0.096676	$0.017676	22%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
XXXX	TE-GSXX	**Small General Service Demand**				
		Basic Service Charge Per Month	N/M	$30.00	N/M	N/M
		Demand 0-7 kW	N/M	$9.95	N/M	N/M
		Demand > 7 kW	N/M	$13.90	N/M	N/M
		Sum kWh	N/M	$0.057500	N/M	N/M
		Win kWh	N/M	$0.047500	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5201	TE-GS11	**Mobile Home Park Service (FROZEN)**				
		Basic Service Charge Single Phase Per Mo.	$15.50	$15.50	$0.00	0%
		Basic Service Charge Three Phase Per Mo.	$20.50	$20.50	$0.00	0%
		Sum kWh	$0.082000	$0.100389	$0.018389	22%
		Win kWh	$0.062000	$0.075904	$0.013904	22%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5213	TE-GS76	**Small General Service Time of Use**				
		Basic Service Charge	$17.50	$15.50	-$2.00	-11%
		Sum On-peak First 500 kWh	$0.099100	$0.094095	-$0.005005	-5%
		Sum On-peak >500 kWh	$0.099100	$0.119550	$0.020450	21%
		Sum Off-peak First 500 kWh	$0.084900	$0.094095	$0.009195	11%
		Sum Off-peak >500 kWh	$0.084900	$0.119550	$0.034650	41%
		Winter On-peak First 500 kWh	$0.081400	$0.069747	-$0.011653	-14%
		Winter On-peak >500 kWh	$0.081400	$0.096676	$0.015276	19%
		Winter Off-Peak First 500 kWh	$0.064900	$0.069747	$0.004847	7%
		Winter Off-Peak >500 kWh	$0.064900	$0.096676	$0.031776	49%
		Base Power Summer On-Peak kWh	$0.050669	$0.060800	$0.010131	20%
		Base Power Summer Off-Peak kWh	$0.026679	$0.025700	-$0.000979	-4%
		Base Power Winter On-peak kWh	$0.032893	$0.056000	$0.023107	70%
		Base Power Winter Off-peak kWh	$0.027092	$0.022100	-$0.004992	-18%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
		Solar Block Rate for Small General Service Rate GS-10	$0.053274	$0.055557	$0.002283	4%
XXXX	TE-GSXXX	**Small General Service Demand Time of Use**				
		Basic Service Charge Per Month	N/M	$30.00	N/M	N/M
		Demand 0-7 kW	N/M	$9.95	N/M	N/M
		Demand > 7 kW	N/M	$13.90	N/M	N/M
		Sum On-peak kWh	N/M	$0.057500	N/M	N/M
		Sum Off-peak kWh	N/M	$0.057500	N/M	N/M
		Win On-peak kWh	N/M	$0.047500	N/M	N/M
		Win Off-peak kWh	N/M	$0.047500	N/M	N/M
		Base Power Summer On-Peak kWh	N/M	$0.060800	N/M	N/M
		Base Power Summer Off-Peak kWh	N/M	$0.025700	N/M	N/M
		Base Power Winter On-peak kWh	N/M	$0.056000	N/M	N/M
		Base Power Winter Off-peak kWh	N/M	$0.022100	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5225	TE-G10BC	**General Service Bright Community Solar**				
		Basic Service Charge Single Phase Per Month	$15.50	$15.50	$0.00	0%
		Basic Service Charge Three Phase Per Month	$20.50	$20.50	$0.00	0%
		Sum First 500 kWh	$0.077000	$0.094095	$0.017095	22%
		Sum>500 kWh	$0.097800	$0.119550	$0.021750	22%
		Winter First 500 kWh 0568	$0.057000	$0.069747	$0.012747	22%
		Winter >500 kWh 0788	$0.079000	$0.096676	$0.017676	22%
		Winter First 500 kWh 0570	$0.057000	$0.000000	-$0.057000	-100%
		Winter >500 kWh 0790	$0.079000	$0.000000	-$0.079000	-100%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		Solar Blocks kWh_2011	$0.028475	$0.028475	$0.000000	0%
		Solar Blocks kWh_2013	$0.033274	$0.033274	$0.000000	0%
		Solar Blocks kWh_20xx	$0.028475	$0.028475	$0.000000	0%
		Credited Solar Blocks kWh_2011	-$0.028475	-$0.028475	$0.000000	0%
		Credited Solar Blocks kWh_2013	-$0.033274	-$0.033274	$0.000000	0%
		Credited Solar Blocks kWh_20xx	-$0.028475	-$0.028475	$0.000000	0%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5230	TE-GSM10	**Small General Service (Municipal Transitional Adjustment)**				
		Basic Service Charge Single Phase Per Month	$15.50	$15.50	$0.00	0%
		Basic Service Charge Three Phase Per Month	$20.50	$20.50	$0.00	0%
		Sum First 500 kWh	$0.077000	$0.094095	$0.017095	22%
		Sum>500 kWh	$0.097800	$0.119550	$0.021750	22%
		Win First 500 kWh	$0.057000	$0.069747	$0.012747	22%
		Win>500 kWh	$0.079000	$0.096676	$0.017676	22%
		Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5231	TE-G10MBC	**General Service (Municipal Transitional Adjustment) Bright Community Solar**				
		Basic Service Charge Three Phase Per Month	$20.50	$15.50	-$5.00	-24%
		Sum First 500 kWh	$0.077000	$0.094095	$0.017095	22%
		Sum>500 kWh	$0.097800	$0.119550	$0.021750	22%
		Win First 500 kWh	$0.057000	$0.069747	$0.012747	22%
		Win>500 kWh	$0.079000	$0.096676	$0.017676	22%
		Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
		RT 43 Water Pumping				
5240	TE-GS36	GS-36 (43) Water Pumping-Firm Service				
		Basic Service Charge Per Mo.	$15.50	$15.50	$0.00	0%
		Sum kWh	$0.068000	$0.083249	$0.015249	22%
		Win kWh	$0.048000	$0.058764	$0.010764	22%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5240	TE-GS37	GS-37 Com Water Pumping-Firm w/ Primary Voltage Discount				
		Basic Service Charge Per Mo.	$15.50	$15.50	$0.00	0%
		Sum kWh	$0.064600	$0.079087	$0.014487	22%
		Win kWh	$0.045600	$0.055826	$0.010226	22%
		Base Power Summer kWh	$0.033355	$0.035459	$0.002103	6%
		Base Power Winter kWh	$0.029955	$0.032111	$0.002156	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5240	TE-GS38	GS-38 (43) Water Pumping-Interruptible Serv				
		Basic Service Charge Per Mo.	$15.50	$15.50	$0.00	0%
		Sum kWh	$0.042000	$0.057200	$0.015200	36%
		Win kWh	$0.027000	$0.037800	$0.010800	40%
		Base Power Summer kWh	$0.031310	$0.033500	$0.002190	7%
		Base Power Winter kWh	$0.028420	$0.030700	$0.002280	8%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

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5240	TE-GS39	GS-39 (43) Water Pumping-Interupt w/Primary Voltage Discount				
		Basic Service Charge Per Mo.	$15.50	$15.50	$0.00	0%
		Sum kWh	$0.039900	$0.054300	$0.014400	36%
		Win kWh	$0.025650	$0.035900	$0.010250	40%
		Base Power Summer kWh	$0.029745	$0.031825	$0.002081	7%
		Base Power Winter kWh	$0.026999	$0.029165	$0.002166	8%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
XXXX	TE-MGS	**Medium General Service**				
		Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
		Summer Demand Charge Per kW	N/M	$8.00	N/M	N/M
		Winter Demand Charge Per kW	N/M	$6.00	N/M	N/M
		Summer kWh	N/M	$0.083249	N/M	N/M
		Winter kWh	N/M	$0.058764	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
		Solar Block Rate for Medium General Service Rate MGS	$0.053227	0.055539		
XXXX	TE-MGSTOU	**Medium General Service TOU**				
		Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
		Demand Summer On-Peak per kW	N/M	$8.00	N/M	N/M
		Demand Summer Off-Peak Excess Per kW	N/M	$4.76	N/M	N/M
		Demand Winter On-Peak Per kW	N/M	$4.00	N/M	N/M
		Demand Winter Off-Peak Excess Per kW	N/M	$3.50	N/M	N/M
		Summer On-Peak kWh	N/M	$0.115800	N/M	N/M
		Summer Off-Peak kWh	N/M	$0.073100	N/M	N/M
		Winter On-Peak kWh	N/M	$0.115800	N/M	N/M
		Winter Off-Peak kWh	N/M	$0.073100	N/M	N/M
		Base Power Summer On-Peak kWh	N/M	$0.060800	N/M	N/M
		Base Power Summer Off-Peak kWh	N/M	$0.025700	N/M	N/M
		Base Power Winter On-peak kWh	N/M	$0.056000	N/M	N/M
		Base Power Winter Off-peak kWh	N/M	$0.022100	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
XXXX	TE-MGSBC	**Medium General Service Bright Community solar**				
		Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
		Summer Demand Charge Per kW	N/M	$8.00	N/M	N/M
		Winter Demand Charge Per kW	N/M	$6.00	N/M	N/M
		Summer kWh	N/M	$0.083249	N/M	N/M
		Winter kWh	N/M	$0.058764	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5300	TE-LGS13	**Large General Service**				
		Basic Service Charge Per Month	$775.00	$775.00	$0.00	0%
		Demand Charge Per kW	$15.25	$10.43	-$4.83	-32%
		Summer kWh	$0.0192	$0.0192	$0.000000	0%
		Winter kWh	$0.0134	$0.0134	$0.000000	0%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5305	TE-LG85	**Large General Service TOU**				
		Basic Service Charge Per Month	$950.00	$950.00	$0.00	0%
		Demand Summer On-Peak per kW	$14.55	$10.43	-$4.13	-28%
		Demand Summer Off-Peak Per kW	$10.92	$10.43	-$0.49	-5%
		Demand Winter On-Peak Per kW	$11.59	$11.59	$0.00	0%
		Demand Winter Off-Peak Per kW	$9.10	$9.10	$0.00	0%
		Summer On-Peak kWh	$0.008600	$0.008600	$0.000000	0%
		Summer Off-Peak kWh	$0.006000	$0.016900	$0.010900	182%
		Winter On-Peak kWh	$0.003000	$0.008600	$0.005600	187%
		Winter Off-Peak kWh	$0.000500	$0.016900	$0.016400	3280%
		Base Power Summer On-Peak kWh	$0.050669	$0.060800	$0.010131	20%
		Base Power Summer Off-Peak kWh	$0.026679	$0.025700	-$0.000979	-4%
		Base Power Winter On-peak kWh	$0.032893	$0.056000	$0.023107	70%
		Base Power Winter Off-peak kWh	$0.027092	$0.022100	-$0.004992	-18%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5322	TE-L13BC	**Large General Service Brigh Community Solar**				
		Basic Service Charge Per Month	$775.00	$775.00	$0.00	0%
		Demand Charge Per kW	$15.25	$10.43	-$4.83	-32%
		Summer kWh	$0.0192	$0.0192	$0.000000	0%
		Winter kWh	$0.0134	$0.0134	$0.000000	0%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		Solar_Blocks_kWh_053227_2P	$0.033227	$0.033227	$0.000000	0%
		Solar_Blocks_kWh_039371_1_1P	$0.029371	$0.029371	$0.000000	0%
		Credited_Blocks_kWh_039371_1_1P	-$0.029371	-$0.029371	$0.000000	0%
		Solar_Blocks_kWh_039371_2_1P	$0.029371	$0.029371	$0.000000	0%
		Credited_Blocks_kWh_039371_2_1P	-$0.029371	-$0.029371	$0.000000	0%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5301	TE-LLP14	**Large Light & Power**		$0.00	$0.00	
		Basic Service Charge	$1,800.00	N/M	N/M	N/M
		Demand Charge	21.98	N/M	N/M	N/M
		Summer kWh	0.0032	N/M	N/M	N/M
		Winter kWh	0.0021	N/M	N/M	N/M
		Base Power Summer kWh	0.031611	N/M	N/M	N/M
		Base Power Winter kWh	0.028388	N/M	N/M	N/M
		PPFAC Charge(1)	$0.006820	N/M	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5309	TE-LLP90	Large Power Service Time of Use				
		Basic Service Charge Per Month	$2,000.00	$2,000.00	$0.00	0%
		Demand Summer On-Peak per kW	$20.49	$25.11	$4.62	23%
		Demand Summer Off-Peak Excess Per kW	$12.49	$12.49	$0.00	0%
		Demand Winter On-Peak Per kW	$15.49	$12.56	-$2.94	-19%
		Demand Winter Off-Peak Excess Per kW	$9.99	$9.99	$0.00	0%
		Summer On-Peak kWh	$0.006900	$0.006900	$0.000000	0%
		Summer Off-Peak kWh	$0.006500	$0.006500	$0.000000	0%
		Winter On-Peak kWh	$0.007500	$0.007500	$0.000000	0%
		Winter Off-Peak kWh	$0.007100	$0.007100	$0.000000	0%
		Base Power Summer On-Peak kWh	$0.045568	$0.057760	$0.012192	27%
		Base Power Summer Off-Peak kWh	$0.023985	$0.024415	$0.000430	2%
		Base Power Winter On-peak kWh	$0.029581	$0.053200	$0.023619	80%
		Base Power Winter Off-peak kWh	$0.024352	$0.020995	-$0.003357	-14%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
XXXX	TE-138	Transmission Service Rate 138kV				
		Basic Service Charge Per Month	N/M	$3,000.00	N/M	N/M
		Demand Summer On-Peak per kW	N/M	$17.15	N/M	N/M
		Demand Summer Off-Peak Excess Per kW	N/M	$12.49	N/M	N/M
		Demand Winter On-Peak Per kW	N/M	$14.15	N/M	N/M
		Demand Winter Off-Peak Excess Per kW	N/M	$9.99	N/M	N/M
		Summer On-Peak kWh	N/M	$0.006900	N/M	N/M
		Summer Off-Peak kWh	N/M	$0.006500	N/M	N/M
		Winter On-Peak kWh	N/M	$0.007500	N/M	N/M
		Winter Off-Peak kWh	N/M	$0.007100	N/M	N/M
		Base Power Summer On-Peak kWh	N/M	$0.056544	N/M	N/M
		Base Power Summer Off-Peak kWh	N/M	$0.023901	N/M	N/M
		Base Power Winter On-peak kWh	N/M	$0.052080	N/M	N/M
		Base Power Winter Off-peak kWh	N/M	$0.020553	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5400	TE-P41&P47	P41 Traffic Signal & Street Lighting				
		Basic Service Charge Per Month	$0.00	$0.00	$0.00	0%
		All Delivery kWh	$0.047600	$0.049623	$0.002023	4%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5402	TE-P50	Lighting Service				
5011	TE-R51 + TE-R5:	100OH	$8.19	$8.54	$0.35	4%
5203	TE-C52 & 52A	100UG	$23.72	$24.73	$1.01	4%
		250OH	$12.29	$12.81	$0.52	4%
		250UG	$27.82	$29.00	$1.18	4%
		400OH	$18.70	$19.49	$0.79	4%
		400UG	$34.23	$35.68	$1.45	4%
		55OH	$8.19	$8.54	$0.35	4%
		55P	$8.19	$8.54	$0.35	4%
		55UG	$23.72	$24.73	$1.01	4%
		70UG	$23.72	$24.73	$1.01	4%
		Pole	$2.86	$2.98	$0.12	4%
		Base Power				
		100OH	$1.34	$1.37	$0.03	2%
		100UG	$1.34	$1.37	$0.03	2%
		250OH	$3.36	$3.42	$0.06	2%
		250UG	$3.36	$3.42	$0.06	2%
		400OH	$5.38	$5.30	-$0.08	-1%
		400UG	$5.38	$5.30	-$0.08	-1%
		55OH	$0.85	$0.87	$0.02	2%
		55P	$0.85	$0.87	$0.02	2%
		55UG	$0.85	$0.87	$0.02	2%
		70UG	$0.94	$0.96	$0.02	2%

Note:
(1) The Present Rate for the PPFAC is the Test Year PPFAC. The Proposed Rate is 0.00%, since the PPFAC rate will be reset to zero for one month when the new base rates become effective. In this proposal the Company has proposed the PPFAC be a percentage based Adjustment applied to base fuel cost for each rate class (e.g. the percentage Adjustment will be the same percentage value regardless of the rate class).

RESIDENTIAL SERVICE RATE R-01

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000			500	1000	>1000						
						$10.00	$0.05910	$0.07910	$0.07910		$0.033801	0.0000%			
Small	520	500	20	0		$10.00	$29.55	$1.58	$0.00		$17.58	$0.00	$58.71	-$0.64	-1.1%
Medium	840	500	340	0		$10.00	$29.55	$26.89	$0.00		$28.39	$0.00	$94.83	$2.34	2.5%
Large	1,250	500	500	250		$10.00	$29.55	$39.55	$19.78		$42.25	$0.00	$141.13	$2.95	2.1%
XLg	1,564	500	500	564		$10.00	$29.55	$39.55	$44.61		$52.86	$0.00	$176.57	$1.83	1.0%
AnnAvg	785	500	285	0		$10.00	$29.55	$22.54	$0.00		$26.53	$0.00	$88.62	$1.84	2.1%
ResAvg	785	500	285	0		$10.00	$29.55	$22.54	$0.00		$26.53	$0.00	$88.62	$1.84	2.1%

RESIDENTIAL SERVICE RATE R-01

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS 500	1000	3500	>3500	Basic Service Charge	Delivery 500	1000	3500	>3500	Base Fuel	PPFAC	Net Bill
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS 500	1000	>1000	Basic Service Charge	Delivery 500	1000	>1000	Base Fuel	PPFAC	Net Bill	$ Change	% Change
					$10.00	$0.05922	$0.07081	$0.08408	$0.037325	0.0000%			
Small	822	500	322	0	$10.00	$29.61	$22.80	$0.00	$30.68	$0.00	$93.09	-$1.12	-1.2%
Medium	1,384	500	500	384	$10.00	$29.61	$35.40	$32.29	$51.66	$0.00	$158.96	-$1.41	-0.9%
Large	1,997	500	500	997	$10.00	$29.61	$35.40	$83.83	$74.54	$0.00	$233.38	-$1.62	-0.7%
XLg	2,430	500	500	1,430	$10.00	$29.61	$35.40	$120.24	$90.70	$0.00	$285.95	-$1.75	-0.6%
AnnAvg	785	500	285	0	$10.00	$29.61	$20.18	$0.00	$29.30	$0.00	$89.09	-$1.07	-1.2%
ResAvg	1,150	500	500	150	$10.00	$29.61	$35.40	$12.61	$42.92	$0.00	$130.54	-$1.35	-1.0%

EXHIBIT
RUCO
9
ADMITTED

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. W-01933A-15-0322

SURREBUTTAL TESTIMONY AND

SETTLEMENT TESTIMONY

OF

FRANK RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 25, 2016

TABLE OF CONTENTS

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services in electric, gas and water utility industry matters, and specializing in the fields of rates, planning and utility economics. My office address is 235 Lark Street, Albany, New York 12210.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, on June 3, 2016 I submitted testimony on behalf of the Residential Utility Consumer Office ("RUCO") with respect to certain revenue requirement issues in this case. On June 24, 2016 I submitted testimony which addressed other aspects of Tucson Electric Power Company's presentation ("TEP" or "the Company") with respect to revenue allocation and rate design. At that time, RUCO witness Lon Huber also submitted testimony with respect to rate design issues.

SCOPE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked to review the Settlement Agreement submitted on August 15, 2016 with respect to the revenue requirement aspects of this case and comment on the rebuttal testimony of parties as it relates to 1) revenue allocation of the rate increase amongst service classes and 2) the proposed consolidation/elimination of many of the lifeline rate rates.

SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Under the terms of the Settlement Agreement TEP shall receive a non-fuel base rate increase of $81.5 million over adjusted test year non-fuel retail revenues. This compares to TEP's initial request for a non-fuel base rate increase of $109.5 million. Of the allowed non-fuel base rate increase, $15.2 million is contingent upon TEP purchasing a 50.5% share of Unit I of Springerville Generating Station ("SGS Unit 1). In the original filing TEP proposed to recover the $15.2 million of costs related to SGS Unit 1 in the PPFAC but now proposes to recover that money in base rates. Thus, the costs related to SGS Unit 1 are revenue neutral and the non-fuel base rate increase in the settlement as compared to the original filing is $66.3 million or $43.2 million less than the Company originally asked for. Stated another way TEP has settled for approximately 60% of the base rate increase it originally sought. I note that many of the adjustments that RUCO witnesses made in original testimony were addressed in the settlement, which I will address in more detail below. Overall while RUCO did not get all it was seeking in the case, and neither did the Company or Staff, I believe the Settlement Agreement is a fair outcome to the rate case.

There is one issue that does not impact the base rate increase addressed in the settlement but does impact the overall rates that customers pay as it would flow through the PPFAC. That issue which was not addressed in the Settlement Agreement is the rate treatment of non-jurisdictional sales above the amount imputed into base rates. Long term wholesale sales, contracts over a year in length, are sold at rates approved by the Federal Energy Regulatory Commission and are known as non-jurisdictional sales. The assets to make these sales are the Company's generating units. For ratemaking purposes an estimate of the amount of non-jurisdictional sales is made and excluded from the income statement. In this case the Settlement imputed a certain number of non-jurisdictional sales but we know that some contracts will be in place after the rates in this case are set and the Company has a long history of entering into these contracts when opportunities arise. If no rate treatment is specified for the treatment of the profits from these transactions the Company will be allowed to retain 100% of profits from generating units whose costs are supported by retail ratepayers. This would be inequitable and I propose that 80% of the profits from these sales be passed back to retail ratepayers and 20% be retained by the Company as an incentive to keep making off system sales when the opportunity arises.

The last issue I address is the importance to note that the Settlement Agreement did not address the rate design aspects of the case and some of those are still in contention. In my original rate design testimony I noted that while TEP proposed revenue allocation did follow the general results of the embedded cost of service study, I believe the relative rates of return of the service classes could be better improved if one more closely followed the results of the cost of service study. I have reviewed the direct testimony of Staff Witness Solganick on this subject as well as the Rebuttal Testimony of Craig A. Jones. I would note that Staff witness Solganick's recommended revenue allocation closely resembled mine. I also note that while Mr. Jones recommended allocation in rebuttal testimony better aligned the recommended revenue allocation with the results of the cost of service study, I believe both mine and Staff's followed the results closer and resulted in rates that were closer to the cost to service as indicated by the cost of service study. At this point in the proceeding RUCO would support Staff's recommend revenue allocation as adjusted for the Settlement Agreement recommended rate increase.

For Lifeline rates, given the very large rate increase that the Company is proposing after reading Mr. Jones rebuttal testimony on this issue, I continue to not support the Company's proposal to reduce the current 27 rate offerings down to 5. As I noted in my original rate design testimony while I do not object to the Company's proposal for new customers where they will receive a fixed discount, the proposal for the existing customers is unacceptable from a customer impact point of view. I propose that the

Company reconsider its proposal and 1) develop a new one where existing frozen classes remain as is, and 2) for non-frozen classes, redevelop a rate proposal that does not result in undue customer rate impacts.

REVENUE REQUIREMENT

Q. PLEASE COMMENT ON THE REASONABLENESS OF THE NON-FUEL BASE RATE INCREASE CONTAINED IN THE SETTLEMENT AGREEMENT.

A. Under the terms of the Settlement Agreement TEP shall receive a non-fuel base rate increase of $81.5 million over adjusted test year non-fuel retail revenues. This compares to TEP's initial request for a non-fuel base rate increase of $109.5 million. Of the allowed non-fuel base rate increase, $15.2 million is contingent upon TEP purchasing a 50.5% share of Unit I of Springerville Generating Station ("SGS Unit 1). In the original filing TEP proposed to recover the $15.2 million of costs related to SGS Unit 1 in the PPFAC but not proposes to recover that money in base rates. Thus, the costs related to SGS Unit 1 are revenue neutral and the non-fuel base rate increase in the settlement as compared to the original filing is $66.3 million or $43.2 million less than the Company originally asked for. Stated another way TEP has settled for approximately 60% of the base rate increase it originally sought.

In my revenue requirement testimony in the case I testified on the proper level of the jurisdictional sales allocator which reflects the impact of wholesale power sales that TEP makes with its generation assets, the proper level of post test year plant, depreciation expense relating to generating plants, weather normalization of residential retail sales and the appropriate rate treatment of the Company's headquarters building. Post test year plant, depreciation expense relating to generating plants, the jurisdictional sales allocator and the rate treatment of the headquarters building were all directly addressed in the terms of the Settlement Agreement. These issues together with other issues raised by the other RUCO witnesses, Mr. Mease and Milchik, most notably rate of return and employee compensation/benefits are all reflected in the terms of the Settlement Agreement and played a significant part in reducing the rate request. Overall, while RUCO did not get all it was seeking in the case I believe the Settlement Agreement is a fair outcome to the rate case.

Q. COULD YOU PLEASE COMMENT ON THE RATE TREATMENT OF NON-JURISDICTIONAL SALES ABOVE THE AMOUNT IMPUTED IN RATES?

A. Yes, the settlement agreement reflects TEP's rebuttal positon on the imputation level of non-jurisdictional sales in rates. Long term wholesale sales, contracts over a year in length, are sold at rates approved by the Federal Energy Regulatory Commission. In the Company's presentation it adjusts the income statement and rate base calculations so that the plant associated with these transactions are not recovered within jurisdictional base rates (Dukes direct at 51). In its original presentation TEP developed their pro-forma adjustment the Company removed 200 MW out of the 296 MW of FERC jurisdictional contracts that were in place in the test year. TEP excluded two expiring long-term wholesale contracts with Salt River Project ("SRP") and Shell Energy (100 MW each) because the SRP contract expired on May 31, 2016 it excluded the Shell Energy contract because it will only be in effect for one year after rates are set in this rate case proceeding (Sheehan rebuttal at page 8). The exclusion of what contracts to include and what contract to exclude became an issue in the rate case and in rebuttal TEP proposed a pro forma adjustments that include a new long-term wholesale contract that was entered into with Navopache Electric Cooperative ("NEC") in September 2015 (Ibid).

While this provides a level of wholesale sales imputed for ratemaking purposes in the Settlement Agreement the issue does not end there. For example we know the Shell contract will be in place after rates are set and if nothing else is done the utility will be allowed to keep all profits from this contract. In addition, per the Company's 2016 IRP we know the contract with the TRICO Electric Cooperative will increase in 2018 from 50 MW to

85 MW and sales will double from 40 GWH to 83 GWH.[1] If this is unaddressed it would just benefit the utility even though we are positive that it is going to happen. Both of these contracts were entered into after the Company purchased Gila River 3 whose costs are now reflected in rates. It is inequitable for the Company to profit off the sales of generator output that is supported by retail customers. The Company should still have an incentive to make these sales, however, or else they just wouldn't bother and both the utility and ratepayers would be worse off. Thus, I propose that 80% of the profits from these sales be passed back to retail ratepayers and 20% be retained by the Company as an incentive to keep making off system sales when the opportunity arises.

REVENUE ALLOCATION

Q. COULD YOU PLEASE DISCUSS THE ISSUE OF REVENUE ALLOCATION?

A. As I noted in my original rate design testimony revenue allocation is a two part exercise where the first step is to correct for any imbalances that exist between service classes in providing the utility an adequate rate of return and the second is to allocate the rate increase among service classes. In the first step, the results of the cost of service study are reviewed to determine how each service classification is doing with respect to providing

[1] TEP 2016 IRP, page 30

the utility with the earned rate of return. If a service class is providing less than the average, in an ideal world, it should be given a greater than average increase to bring its earned rate of return up to the average. For example, if the utility is earning a 10% overall average rate of return and one particular service class is earning a 7% rate of return while another is earning a 13% rate of return, then the rate designed would give a higher than average increase to the first service class, in the example, and a lower than average increase to the second service class, in the example.

Q. COULD YOU PLEASE SUMMARIZE WHERE PARTIES ARE AT THIS STAGE IN THE PROCEEDING?

A. Yes. In my original rate design testimony I proposed an alternative to the Company's recommended allocation and I note that Staff did as well. The Company adjusted it position in the rebuttal testimony of Craig Jones. While mine and the Company's original position was based on TEP's original proposed revenue requirement, Staff's recommended allocation was based on its recommended revenue requirement and the Company's rebuttal positon was based on its updated revenue requirement. In order to get each parties positon on revenue allocation in the proper perspective of one another I developed the table below which shows how much each party is allocating to a service class relative to the overall average. Put another way, if a party is recommending one service class get a 15% increase while the utility overall is getting a 10% increase then that class would be getting 1.5 times the average. If the overall average was 8% and the service class was getting a 12% increase it would be still getting 1.5 times the average increase. Again, any time a service class gets more than an average increase it improves the relative rate of return of the class.

TEP
Revenue Allocation - % Increase Relative to Overall Increase

	Company Original	Staff	RUCO	Company Rebuttal	UROR as Filed
Res	0.88	1.90	1.60	1.39	-0.29
GS	0.24	0.16	0.39	0.18	3.50
LGS	3.07	0.21	1.03	2.45	0.83
LPS	0.11	n/a	0.30	-5.31	2.42
Lighting	2.09	4.25	1.66	2.65	-2.86
Total	1.00	1.00	1.00	1.00	1.00

I have also included a column which shows the relative contribution of each service class relative to the Uniform Rate of Return. This is helpful as a metric to compare how each service class is providing a rate of return relative to the overall rate of return of the utility. For example if the utility is earning an overall 8% rate of return and service class ABC is earning an 6% rate of return it is 0.75 relative to the total. If service class XYZ was earning a 13% rate of return it would earning 1.625 times relative to the total. This way one can easily see that a service class with a relative rate of return lower than 1.0 should get an above average increase and one with a relative rate of return greater than 1.0 should get a less than average increase.

Based on this table I conclude that both Staff and my recommended revenue allocation are most in line with the results of the cost of service study and either could be used to set rates. Staff's method was based on a series of runs of the cost of service model and moving the Residential and Lighting Classes closer to parity (Solganick Direct at page 23). They then chose one that they thought best balanced rate impacts and the results of the cost of service study. My method was more based on first rate impacts and second on the results of the cost of service study. That cannot be said for the Company's original or rebuttal position. In both cases it punishes the Large General Service Class by giving much higher increases while favoring the Large Power Service Class. Staff's method is more formalistic and can be more easily used in whatever revenue requirement results from the case as it is based on a precise measure of how much each class should move. As such, I recommend that Staff's method be used to design the final revenue allocation in the case.

RATE DESIGN

Q. WHAT IS YOUR RECOMMENDED RATE DESIGN FOR THE LIFELINE RATES?

A. In its original presentation Company witness Jones proposed major changes to its low income rates which are referred to as Lifeline rates. The Company proposes to change the current rates that give either a fixed discount or discounts from the otherwise applicable rates to a single uniform discount off of each of the residential rates (Jones Direct at 57). The modifications would reduce the 27 existing tariffs down to five different open rate options, one for each of the five existing residential rates, and apply a flat $15.00 per month discount, limited to a reduction of the bill down to zero dollars (Ibid). The Company is also proposed changes to its frozen Lifeline rate options that will reduce them from 22 to five different options (Jones Direct at 58).

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S PROPOSAL?

A. In my rate design testimony I noted that the Company's proposal resulted in very large rate increases to the customers being served under the lifeline rate options being proposed by the Company (Radigan Direct on Rate Design at 10). Moreover, I noted that the Company's proposal is not supported by the facts as presented. Many of these existing rates receive either a fixed discount in dollars or a discount as a percentage. As these are existing in the current billing program there is little administration to them. In addition, many of these rates are frozen, 22 of them, and don't even apply to new customers. The fact that the Company states that 11 of the 27 rate schedules have less than 20 customers on them so the question must be asked as to why even bother going to so much effort for so few (Ibid). In rebuttal testimony Mr. Jones states that I make light of the burden this puts on the Company (Jones Rebuttal at age 49). He notes that it is burdensome because no matter how few customers the class is tracked for reporting purposes and be included in every report (Ibid). He states this takes a great deal of time and effort (Ibid).

Mr. Jones also responded to my comment that I could find no evidence that it proposed the envisioned cost reductions due to the elimination of these service classes by stating that the Company is trying to identify an area that can be streamlined in a way that will eventually allow for more productive use of employees time and our customer's dollars (Jones rebuttal at 50, emphasis added).

Q. PLEASE RESPOND TO MR. JONES.

A. I do not make light of the situation but I must note that these are exiting customers who are already in the billing system, already in all reports and most of the rate frozen so that new customers are not allowed in which would add to the Company's daily work load. I do not discredit that the Company has to put effort into maintaining these rates but I balanced that against the large increases being proposed (Per Jones Rebuttal CAJ R-3, Schedule H 2-2 some lifeline rate options receiving 50% increases per subclass) and simply stated that the Company's proposal not be imposed on existing customers due to the rate impacts. I also balanced the fact that the Company's proposed cost savings are unidentified and may only occur far out into the future. In sum, I do not make light of the Company's presentation but could find no evidence that it has merit when measured against the certain large rate impacts being proposed.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY AND TESTIMONY IN SUPPORT OF THE SETTLEMENT?

A. Yes, it does.

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322

EXHIBIT
RUCO
10
ADMITTED

DIRECT TESTIMONY

OF

LON HUBER

ON

RATE DESIGN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 24, 2016

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Exhibits

EXECUTIVE SUMMARY

The Residential Utility Consumer Office ("RUCO") has reviewed the testimony of Tucson Electric Power, Inc. ("Company" or "TEP") on rate design. The Company's proposal can be summarized by the following four points;

- Increasing the basic service charge for residential and general service customers,
- Reducing the number of volumetric tiers from four to two tiers,
- Creating a new net-metering rider for DG customers with the export rate linked to a utility scale PPA price.
- Requiring all new distributed generation (DG) customers to move to a three-part rate.

The Company's proposal for DG customers focuses on fixed cost recovery. While RUCO thinks this is important, RUCO also believes better price signals can and should be sent to DG adopters. A balance between fixed cost recovery and accurate price signals that reduce long-term costs for ratepayers must be obtained.

The attached rate designs are for illustrative purposes, using preliminary numbers to give parties an indication of the level of price signals RUCO deems appropriate to send. Full rate schedules will be developed once RUCO reviews the positions of other parties and receives further input from stakeholders.

RUCO continues to recommend a traditional rate design for the vast majority of TEP customers along with a serious commitment to rate modernization and peak demand reduction.

To achieve this, RUCO presents the following recommendations:

- Stable fixed charge
- Three tier inclining block rate
- A default three tier time of use (TOU) rate for high energy users with a three-hour peak
- Optional three part TOU rate

RUCO continues to believe that DG customers need to be treated fairly but uniquely given their distinct attributes from adopting advanced technology. Therefore, RUCO is putting forward four options for these partial requirements customers:

- Advanced DG rate
- Renewable Energy Standard Credit Option
- DG Volumetric TOU with Grid Export Fee
- All Rate Option
    - Opt-out Adjustment Fee
    - Market Based Export Option

I. INTRODUCTION

Q. Please state your name, position, employer and address for the record.

A. Lon Huber. I am a Director at Strategen Consulting LLC located at 2150 Allston Way # 210, Berkeley, CA 94704.

Q. Please state your educational background and work experience.

A. My career in the energy industry began in 2007 when I started working at a research institute housed within the University of Arizona. In 2010, I became the governmental affairs staffer for TFS Solar, a solar photovoltaic ("PV") integration company based in Tucson. I was hired by Suntech America in 2011 where I led the company's regulatory and policy efforts in numerous US states until December 2012. In 2013 I served as a consultant for the Residential Utility Consumer Office ("RUCO") on energy issues. I joined RUCO as a full time employee in January 2014. Since March 2015 I have worked at Strategen Consulting where I continue to advise RUCO on energy policy matters. I obtained a Bachelor of Science Public Administration degree in Public Policy and Management from the University of Arizona in 2009. I also received a Master's of Business Administration from the Eller College of Management at the same university. A full resume is attached in Exhibit LH-1.

Q. What is the purpose of your testimony?

A. My testimony will address the Company's rate design proposals and present RUCO's proposed rate design and policy.

Q. How is your testimony organized?

A. My testimony is presented in five sections. Section I is the introduction. Section II provides a summary of the issues with Company's proposal for all customers. Section III addresses RUCO's rate design and policy recommendations for all customers. Section IV summarizes the issues with the Company's proposal regarding DG customers. Finally, section V is RUCO's rate design and policy recommendations for DG customers.

Q. In summary, what are RUCO's comments regarding the Company's proposal?

- As proposed, a 100% increase in customer fixed charges is unprecedented and unwarranted.
- RUCO agrees that four tiers are not necessary, but disagrees that two is the optimal number of tiers.
- Rates should begin to send time and season differentiated price signals to all customers.
- Reforming distributed generation compensation is necessary, but RUCO has concerns with the Company's approach.

- RUCO supports optional three part rates, carefully crafted volumetric time of use rates, and a renewable portfolio standard linked kWh credit rate for solar customers.

Q. What principles does RUCO believe should inform this rate-making proceeding?

A. RUCO uses the following principles as a guide to rate-making in this case:

1. Do not inhibit conservation related price signals
2. No substantial changes for 98% of TEP ratepayers to accommodate 2% of DG adopters; however, standard rates do need to start evolving
3. Send more accurate price signals to DG customers through peak demand focused TOUs
4. Create options for future solar customers through RES compliance driven fixed solar credit

Additionally, RUCO supports Bonbright's principles or rate design, particularly the following summarized by the National Association of Regulatory Utility Commissioners ("NARUC")[1];

- Simplicity, understandability, public acceptability and feasibility of application and interpretation

[1] http://pubs.naruc.org/pub/538EA65C-2354-D714-5107-44736A60B037

- Stability of rates themselves, minimal unexpected changes that are seriously averse to existing customers
- Fairness in apportioning cost of service among different consumers
- Avoidance of "undue discrimination"
- Efficiency, promoting efficient use of energy and competing products and services

Q. Does RUCO believe TEP's proposed rates follow the above principles?

A. Not entirely.

Q. What changes could TEP make to better align with the above principles?

A. As further defined below in section II, RUCO recommends the Company implement the following for standard customers:

1. Stable fixed charge linked to customer specific costs
2. Three tier inclining block rate
3. A default three tier TOU rate with a three-hour peak for high use customers
4. Optional three part TOU rate

II. ISSUES WITH THE COMPANY'S PROPOSAL FOR ALL RESIDENTIAL CUSTOMERS

Q. What are the primary issues of concern that RUCO has identified within the Company's proposal that affect all residential customers?

A. RUCO has identified two primary issues of concern that affect all residential customers: 1) the Company's proposal to increase its basic service charge (or fixed customer charge); and 2) the Company's proposal to eliminate the top tiers from its inclining block volumetric rate.

1) <u>BASIC SERVICE CHARGE</u>

Q. Has RUCO adopted a general position regarding fixed customer charge increases?

A. RUCO is a member of the National Association of State Utility Consumer Advocates ("NASUCA"), which has taken a position on this issue.

Q. What is NASUCA?

A. NASUCA is an association comprised of many consumer advocates from numerous states and the District of Columbia. NASUCA's members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts.

Q. What is NASUCA's position on increased fixed customer charges?

A. NASUCA recently adopted resolution 2015-1, which opposes utility efforts to increase fixed customer charges. I have included a copy of this resolution with this testimony (see Exhibit LH-2).

Q. Does the Company's proposal include an increased fixed customer charge?

A. Yes, the Company proposes to double its basic service charge, increasing it from \$10 to \$20 per month for standard residential customers of tariffs TE-R-01, TE-201A, TE-R01BC, TER-01LL, TE-R01LB, and TE-201AL. The Company has also proposed to increase its basic charge from \$6.90 to \$12.00 for limited income customers on tariffs TE4-01, TE5-01, TE6-01, TE6-201A, TE8-01, TE8-201A, and TE6-01BC. Similar increases are proposed for customers on all other residential tariffs.

Q. Does RUCO support the Company's proposal to increase in the basic service charge for residential customers?

A. No.

Q. Why does RUCO oppose the Company's proposal to increase its basic service charge?

A. There are several reasons. First, the proposal is based on the faulty premise that fixed costs must be recovered through fixed charges. Second, the proposal deviates from common utility practice. Third, the proposal does not adhere to the principle of cost causation. Fourth, the Company's proposal is regressive and would disproportionately impact limited income customers. Fifth, the proposal reduces the incentive for customers to conserve energy. Sixth, the proposal does not adequately account for impacts to the Company's risk profile. I will explain each of these in more detail in my testimony below

Q. What is the Company's rationale for increasing the basic service charge?

A. The Company believes that its basic service charge should be increased as a means to recover its fixed costs. The Company states, "Considering that all electric utilities incur substantial fixed costs to serve residential customers, and that those fixed costs typically exceed the higher basic service charges approved for those utilities, TEP's current monthly service charge should be increased."[2]

Q. Does RUCO agree with the premise that fixed costs should be recovered through higher fixed charges?

A. No. There is no fundamental reason that fixed costs must be recovered through fixed prices. In fact, many industries in the global economy incur fixed costs that are ultimately recovered through prices that are not fixed. For example, gasoline is priced on a volumetric basis ($ per gallon), despite the fact that there are many fixed costs associated with its production (e.g. refineries, pipelines, etc.).

[2] Testimony of Craig Jones, p 43.

According to Bonbright, "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of a complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation, but subject to the market forces of competition."3 Thus, if rates are intended to emulate prices charged by competitive enterprises, there is no rationale for regulated utilities to implement fixed charges instead of other pricing options. Bonbright goes on to say that "regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions."[4] By proposing to recover more its costs through fixed charges the Company is in essence attempting to insulate itself in part from adverse business conditions.

Q. Other than increasing fixed charges, are there other ways utilities such as TEP could recover fixed costs?

A. Yes there are several. These range from implementing time-of-use rates to simply increasing TEP's current volumetric rates.

Q. How does the Company's proposed increase in the basic service charge deviate from common utility practice?

A. Recent decisions by commissions in several states have either denied entirely or scaled back proposals to increase fixed charges proposed by utilities. Synapse

[3] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 141
[4] *Ibid.* page 382

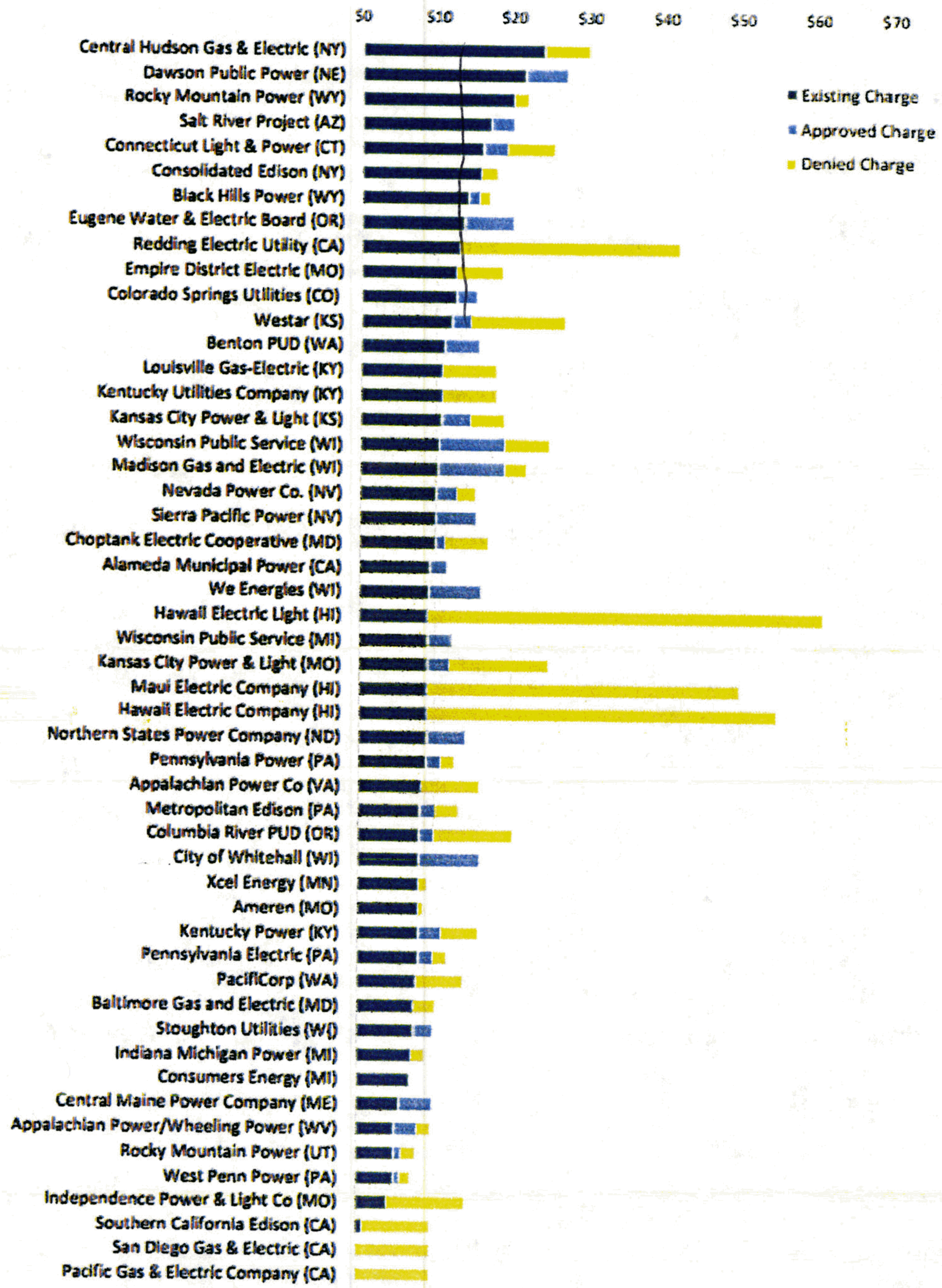
recently analyzed 51 proposals decided between September 2014 and November 2015 and found that 41% of these proposals were rejected, while 33% were scaled back. The average approved fixed charge for these decisions is $11.87.[5] These decisions are summarized below.[6]

Ibid. page 382

Whited, M., Woolf, T., Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity. p 43.

[6] *Ibid.* p 46

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

Q. What are some of the reasons that these proposals were denied or scaled back?

A. There are many reasons why these proposals were denied or scaled back. Some include: concerns about reduced customer control; concerns about rate shock; concerns about inequitable impacts to low usage customers; concerns about inequitable impacts to low income customers; concerns about reduced incentives to invest in energy efficiency; and concerns about inefficient price signals.

Q. Can you provide a few examples of Commission decisions regarding fixed charges?

A. Yes. When the Missouri Public Service Commission denied Ameren Missouri's request to increase its fixed charge it stated, "There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy."[7] Similarly, when the State of Illinois Commerce Commission rejected Peoples Gas and North Shore Gas' proposals, it stated, "It is patent that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller

[7] Missouri Public Service Commission (2015). Report and Order in the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service. See discussion on page 76-77.

portion of the bill is subject to variable usage charges and customer efforts to reduce usage."[8] Finally, the Minnesota Public Utilities Commission (MPUC) recently rejected CenterPoint's proposed customer charge increase and ruled to maintain it at the existing level. Similar to the present case, the CenterPoint argued that "increasing the customer charges would reduce intraclass subsidies." However, the MPUC noted in its decision that "this conclusion is based on the premise that the charges are currently set below cost—a premise on which the OAG has cast significant doubt."[9]

Q. Did the Company provide examples of any utilities with basic service charges at or near the $20 level?

A. Yes. The Company stated in their testimony that, "APS, Trico Electric Cooperative, Inc. and Salt River Project ("SRP") have basic service charges ranging from $15.00 to $20.00 per month."[10]

Q. Does RUCO believe these examples lend support to the Company's proposal?

A. No. For APS, the current basic service charge for standard residential customers is actually $0.285 per day, or about $8.67 per month – significantly less than the

[8] State of Illinois Commerce Commission (2015). Order North Shore Gas Company, proposed general increase in gas rates; The Peoples Gas Light and Coke Company, Proposed general increase in gas rates. See discussion on page 176.
[9] Minnesota Public Service Commission (2016). In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota, Docket No. G-008/GR-15-424. p 64.
[10] Testimony of Craig Jones, p 43

$20 per month proposed. Of the remaining utilities, only SRP reaches $20 per month for standard residential customers. However, RUCO believes this example is an extreme outlier that was established under very different circumstances than the Company's present case and is not representative of recent trends. For example, RUCO recently reviewed the basic service charge for 25 investor-owned utilities in the Southwestern U.S. and found that 18 of them (72%) have a basic service charge of $10 per month or less.

Q. How does the Company's proposed basic service charge fail to adhere to the principle of cost causation?

A. RUCO believes that rates should reflect the principle of cost causation, absent policy considerations. As such, RUCO further believes that customer charges should only be used to recover the incremental costs that arise from serving individual customers. This includes costs associated with metering, billing, and service line drops. Meanwhile, it excludes costs related to overall demand on the system, such as transformers or distribution poles and wires. Such costs are common to (i.e. "attributable to" or "caused by") a larger group of customers and, therefore, should not be recovered on an individual customer basis. The Company's proposal of a $20 basic customer charge appears to greatly exceed the individual customer cost elements.

Q. What is the minimum distribution system approach or "minimum system method"?

A. Under the minimum system method, a portion of distribution plant costs (e.g. lines, poles, transformers) are allocated to a customer class based on the number of customers. The Company relies on this method as justification for its proposed basic service charge.

Q. Does RUCO support this approach?

A. No, RUCO does not. The minimum system method is flawed in that it assumes that the configuration of the distribution network is a given. However, the placement of substations, the number of feeder lines, and the current-carrying capacity of distribution system components are all dependent upon expectations about demand, voltage drop, and other factors. Additionally, the number of poles and length of power lines is also partly dependent on the size and spacing of customer properties, not on the number of customers. Recovering a large share of distribution system costs through customer charges is equivalent to assessing a per person tax that reflects neither the customer's ability to pay nor the benefits received. Given these considerations, RUCO agrees with Bonbright's statement that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible."[11]

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[11] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 348

Q. Have other commissions weighed in on the use of the minimum system method?

A. Yes. For example, the Illinois Commerce Commission explicitly rejected its use, stating the following:

"As it has in the past, see, e.g. Dockets 05-0597, 99-0121 and 00-0802, the Commission rejects the minimum distribution or zero-intercept approach for purposes of allocating distribution costs between the customer and demand functions in this case. In our view, the coincident peak method is consistent with the fact that distribution systems are designed primarily to serve electric demand. The Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic. We reject the use of the MDS in this proceeding, and find that ComEd's ECOSS was correct in not reflecting the MDS concept. Accordingly, the Commission rejects the use of IIEC's COSS because it relies on the use of MDS."[12]

Q. What method does RUCO support instead of the minimum system method?

A. RUCO supports the basic customer method, which only allocates customer-specific costs (and not other distribution costs) based on the number of customers.

Q. Is this method used in other jurisdictions?

A. Yes. Several states including Maryland, Texas, Arkansas, Colorado, and Illinois all use the basic customer method for allocating customer costs.

[12] Illinois Commerce Commission, Docket No. 07-0566, Final Order dated Sept. 10, 2008, p. 208.

Q. How would the calculation of the basic service charge differ under this method?

A. Under the basic customer method, the cost elements for individual customers are significantly lower than the Company's proposed $20 basic customer charge.

Q. Does RUCO have any evidence to support this?

A. Yes. According to Exhibit CAJ-1 of the Company's testimony, the marginal cost of serving a residential customer was $353.86 in 2015. However, this total includes certain shared costs items such as $81.49 for "Line Transformers" and $148.28 for "Conductors & Devices." As explained previously, it is not appropriate for these shared cost items to be recovered through the basic service charge. Once these elements are removed, RUCO calculates the marginal cost to serve an individual customer to be $124.09 or about $10.34 per month. This is roughly equal to the Company's current basic service charge and far less than the proposed $20 amount.

Q. What is the significance of the fact that these are marginal costs?

A. Marginal costs reflect the incremental costs to serve customers on a forward looking basis. However, utility rates are frequently set to recover average or embedded costs. Meanwhile, embedded costs are typically lower than the marginal cost, a notion that is demonstrated in the Company's testimony.[13] Thus,

[13] See Craig Jones, Table 1, p 31.

RUCO believes the customer cost of $10.43 calculated should serve as an upper bound when considering how to set an appropriate basic service charge.

Q. On what basis should the costs of shared distribution infrastructure be recovered?

A. RUCO believes that shared distribution costs should be recovered based on "benefits received." As an example, the logic of benefits received would tell us that a household using 500 kWh a month should not have to pay the exact same price for utility poles as a household using 2,000 kWh a month.

Q. Please explain why "benefits received" is a sound basis for recovery of shared costs?

A. In most forms of shared infrastructure in the civic sector, costs are recovered either through usage fees (e.g. bridge tolls) or taxes (e.g. property taxes). The latter reflects the notion of a customer's "ability-to-pay" while the former reflects the notion of "benefits-received" by the customer. While recovery of costs through an ability-to-pay approach (e.g. through tax subsidies) can be common for municipal utility systems (e.g. water and sewer), it is not practically feasible for privately owned utilities. This leaves benefits-received as the primary basis for recovering shared infrastructure from private electric utilities. Meanwhile, the best measure of benefits-received for an electric utility is energy consumption.

Q. Can you please provide an example?

A. Yes. Consider two customers on a shared distribution system that are similar in all respects except that one is consuming electricity 24-7, while the other only operates for eight hours a day. Under this scenario, the 24-7 customer is receiving more benefits from the shared distribution system.

Q. How does the Company's proposed basic service charge reduce the incentive for customers to conserve energy?

A. Under the company's proposal, a significantly greater share of each customer's bill will be collected through a fixed charge as opposed to a volumetric energy rate. Thus, if the company's proposal were adopted, each customer would have a much smaller portion of their bill over which he or she has control. For example, Schedule H-4 demonstrates that an average residential bill for a TEP customer in winter would be about $86.78 under present rates, with $10 recovered through the basic service charge and $98.62 under proposed rates, with $20 recovered through the basic service charge.[14] This means that under present rates, customers are unable to control 11.5% of their energy costs, but under the proposed rates they would be unable to control 20% of their energy costs. Thus, under the Company's proposal there would be significant increase in the portion of customers' bills over which they would have not be able to manage through energy conservation or other means.

[14] Schedule H-4, page 1 of 85, Winter.

Additionally, by proposing to recover more of the Company's fixed costs through a fixed rate, the resulting volumetric rate included in the Company's proposal is lower than it otherwise might have been. A lower volumetric rate dampens the price signal customers receive, further reducing the incentive for customers to conserve energy. RUCO supports strong incentives for customers to conserve energy due to the significant benefits that peak reducing energy efficiency can bring to all ratepayers. As such, RUCO does not support the Company's proposal to recover increased share of its costs through fixed rates.

Q. Has RUCO considered how the Company's proposed basic service charge would impact limited income customers?

A. Yes. In general, limited income customers also tend to be low-use customers.[15] Thus, any proposal that has a greater impact on low-use customers will also have a greater impact on limited income customers. Meanwhile, proposals to increase fixed charges often have a greater impact on low-use customers.[16]

[15]According to the EIA's Residential Energy Consumption survey, households in the Western U.S. that are 150% above the federal poverty line consume 29% less energy than households with incomes below that level. Also, total household energy consumption in Western U.S. households increases by 11% on average per $20,000 increase in household income.
Source: U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Forms EIA-457 A and C-G of the 2009 Residential Energy Consumption Survey.

[16] Expenditures on energy as a percent of household income was 8% for the median low income household in Phoenix versus 4% of all households (Tucson data not available).
Source: American Council for an Energy-Efficient Economy and Energy Efficiency for All (2016) Lifting the High Energy Burden in America's Largest Cities.

Q. Has RUCO compared the impact of the Company's proposal on low-use versus high-use customers?

A. Yes. For example, RUCO compared the average bill increase for a low-use residential customer (822 kWh, summer) as estimated by the Company under its proposal would be $11.49 or about 12.2%.[17] Meanwhile, the summer bill increase for a high-use residential customer (2,430 kWh, summer) is only $5.21 or about 1.8%. In both cases, the bill increase is primarily attributable to the same increase in the basic service charge. However, it is clear that the low-use customer's bill increases by a much greater percentage. RUCO is particularly concerned with this higher impact on low-use customers since many of these customers are on fixed incomes and have less ability to increase payment for electric service without decreasing payment for other fundamental needs (e.g. food, medicine, etc.). In RUCO's view, the proposed basic service charge increase is a regressive policy that is harmful to Arizona's most vulnerable population.

Q. How does the Company's proposed basic service charge fail to account for impacts to the Company's risk profile?

A. Under the Company's proposal, a much greater portion of the overall revenue requirement would be recovered through the basic customer charge. Although revenue collected through this charge presents some risk of under recovery (i.e. if customers leave the service territory), this risk is substantially lower than revenue recovered through volumetric energy or demand based rates, which depend on

[17] Schedule H-4, page 2 of 85, Summer.

factors such as weather and economic growth. In its proposal, the Company fails to account for this reduced risk in developing the appropriate rate of return to utility investors.

Q. Please explain the connection between risk and reward for utility investors as it pertains to this proposal.

A. Generally speaking, utility company shareholders take on some risk when providing capital for utility investments. In exchange for putting their capital at risk, investors have the opportunity to earn a return on that investment, which is determined in part by the Return on Equity (ROE) set by the Commission. Ideally, the ROE set by the Commission will perfectly reflect the risk and reward preferences (i.e. the cost of capital) of utility investors. Thus, if the risk of capital cost recovery is substantially altered, the ROE should also be modified to reflect that fact. The Company's proposal does not appear to include any adjustments to the proposed ROE that account for the fact that substantially more of the company's revenue is collected through a lower-risk mechanism.

2) <u>MODIFIED TIERS</u>

Q. Please describe how the Company proposes to change its volumetric rates for standard residential customers.

A. Presently, the Company implements an inclining block rate for standard residential customers that includes four usage tiers.[18] The Company proposes to eliminate

[18] Tier 1 ranges from 0-500 kWh

the third and fourth tiers of the residential rate class. This would leave only two usage tiers: 0-500 kWh usage and usage above 500 kWh.

Q. Does RUCO support the Company's proposal to eliminate the top two usage tiers for residential customers?

A. Partially. RUCO believes it is appropriate to eliminate the top usage tier (>3,500 kWh). However, RUCO does not support the elimination of the third usage tier (>1,000 kWh).

Q. Why does RUCO support the elimination of the top usage tier (>3,500 kWh)?

A. The elimination of this tier is likely to have minimal impact on the vast majority of residential customers. Based on RUCO's analysis of customer billing data provided by the Company, it appears that only a small number of customer bills and revenues collected (approximately 1% each) are associated with this tier.[19]

Q. Why does RUCO oppose the elimination of the third usage tier (>1,000 kWh)?

A. Unlike the top tier, a significant number of customer bills and revenues collected are associated with this usage tier.[20] The elimination of this tier therefore will have a significant impact on a large number of customers.

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[19] Calculated from data presented in Schedule H-5 of the Company's testimony.

[20] Based on data presented in Schedule H-5 of the Company's testimony, RUCO estimates that approximately 40% of customer bills and 34% of revenue collected are presently associated with tier 3.

Q. Are there specific customer impacts RUCO is concerned about if this tier is eliminated?

A. Yes, there are two impacts we are most concerned about. One relates to bill impacts for low use customers, the other relates to the price signal for energy conservation.

Q. Please elaborate.

A. First, by eliminating the third tier, a greater share of the utility's costs must be recovered through the first and second tiers. This means that the rate increase proposed for first and second tier customers is significantly higher than it otherwise might have been if the third tier remained intact. RUCO is concerned about this because lower usage customers, who also tend to have less income and less discretion over their energy consumption, will likely experience significant bill and rate increases. For example, the table below illustrates the proposed rate increase for customers in the first two usage tiers will be 5% and 18% respectively in the summer.

Table 1. Summary of Proposed Changes to Rates and Customer Bills for Volumetric Rate Tiers[21]

Tier	Present Rates (Summer)	Proposed Rates (Summer)	Rate Increase (%)	Customer Bill Count (% of total, Summer)
0-500 kWh	$0.0562	$0.0591	5%	30%
501-1000 kWh	$0.0672	$0.0791	18%	29%
1,001-3,500 kWh	$0.0798	$0.0791	-1%	40%
>3,500 kWh	$0.0882	$0.0791	-10%	1%

RUCO believes that concentrating bill increases on lower usage customers is a regressive policy that should be avoided. Additionally, it is counterintuitive since these customers generally contribute less to overall system costs. Moreover, these issues would be exacerbated by the adoption of the Company's proposed increase in the basic service charge.

Second, by eliminating the higher tier, higher usage customers will actually experience a decrease in the marginal price per kWh consumed. RUCO is concerned about this because it will reduce the price signal to save energy for the group of customers with the highest consumption. For example, the table above summarizes the changes to the tiered rates for each usage tier under the Company's proposal. It suggests that approximately 41% of customers who are higher-use customers will experience a rate decrease in the summer. The Company has proposed this despite the fact that these high-use customers are

[21] TEP Testimony, Schedule H-5.

likely to have the greatest discretion over their energy usage. Since reducing overall energy consumption provides a benefit to all customers over the long run, RUCO supports strong price signals for energy conservation.

III. RUCO'S PROPOSED RATE DESIGN AND POLICY FOR ALL CUSTOMERS

Q. Please detail RUCO's proposed changes to the fixed customer charge.

A. RUCO proposes the customer charge remain at current levels across the board. For the typical non-TOU residential customer, the charge would be $10.

Q. How does RUCO's method to determine the fixed charge differ from the Company's method?

A. RUCO uses the Basic Customer method for determining a customer's fixed charge. This method accounts for service drop, meters, and billing and allows TEP's rate to remain unchanged in this proceeding. The Company chose to use the Minimum System method to expand the charge to include shared infrastructure expenses that are partly demand related including poles, wires, and transformers. These expenses are not customer charges and should not be recovered as such.

Q. Please detail RUCO's proposed changes to the volumetric rate.

A. RUCO proposes to implement a three-tiered inclining block structure. Such a structure relieves pressure off of low users and prevents less revenue from being shifted to collection via basic service charge over which customers have no control.

Q. Please detail RUCO's proposed changes to high use customers.

A. For customer using 950 kWh or more per month on average over an entire year, RUCO proposes transitioning these customers to a three-tier volumetric TOU rate with a summer peak from 3:00 PM to 7:00 PM and a winter peak from 6:00 AM to 9:00 AM. These customers would be placed on the TOU rate plan by default. However, for the time being, these customers would also have the ability to opt-out and return to the inclining block rate plan. According to studies RUCO has reviewed, most customers tend to stay on their default rate plan. Thus, if designed correctly, the number of customers that choose to opt-out should remain low.[22]

Q. Why does RUCO support a four-hour summer peak period?

A. RUCO believes that a four-hour period will be easier for customers to manage than TEP's current six hour TOU peak, particularly for customers lacking advanced technology. Meanwhile, the four-hour period RUCO is proposing will still align with the top peak hours of residential demand. An estimate of the on-peak and off-peak rates are attached in exhibit LH-3.

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[22] Cappers, Peter C., et al. (2016) *Time-of-Use as a Default Rate for Residential Customers: Issues and Insights,* pg. 14

Q. Why did RUCO select 950 kWh of consumption as the basis for the default TOU rate?

A. About 25% of the residential TEP customer base falls into this category. RUCO believes that this level of energy indicates enough usage to load shift during all or parts of the on-peak window.

Q. What are the benefits of RUCO's proposed change?

A. This change would introduce hourly as well as seasonal variations in residential rates, thereby providing price signals that more accurately reflect utility cost drivers. Moreover, this structure would help to reduce intraclass subsidies between winter and summer customers as well as between customers whose usage primarily occurs either on-peak or off-peak. Finally, it is gradual and optional.

Q. What implementation strategies can help ensure successful adoption?

A. RUCO encourages the Company to undergo bill redesign and form educational efforts around the TOU rates. These educational efforts could include bill inserts, advertising and media campaigns, online information, and outreach to local community groups. Once the default TOU rate plan is successfully in place for this group of high-use customers, other customer groups (e.g. new customers) could also be considered for placement on a default TOU rate. RUCO also recommends that a study be conducted on the effectiveness of this rate plan for reducing peak demand.

IV. ISSUES WITH THE COMPANY'S PROPOSAL FOR DG CUSTOMERS

Q. Please detail the Company's proposed for customers with distributed generation.

A. The Company proposes to create a new net metering rider with three-part rates. This new net metering rider will be default for all partial requirement customers that submitted an interconnection application after June 1, 2015. Currently interconnected customers will stay on their current rates until they expire in 20 years.

Q. How will the new net-metering rider compensate DG customers?

A. New DG customers will be compensated for excess energy at a Renewable Credit Rate. The Renewable Energy Credit rate is a variable proxy for the price TEP will pay for energy from utility scale assets. The variability in the Renewable Energy Credit rate would be based on most recent utility scale PPA price. The Company "believes it is appropriate that Net Metering customers receive the same financial compensation for their distributed energy that is available from other, larger, more cost-effective resources."[23] The Company also proposes to eliminate the banking option by purchasing excess energy during each billing cycle.

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[23] Direct Testimony of Carmine Tilghman, pg. 10

Q. What is a partial requirement customer?

A. The Company defines partial requirement customers as DG customers with net metering.[24]

Q. Does RUCO agree with this classification?

A. Yes. RUCO witness Frank Radigan will comment on this topic.

Q. Does the Company's proposal send accurate price signals to new DG customers?

A. No. The proposed structure is intended to increase fixed cost recovery, rather than send correct price signals to customers. RUCO understands the need to recover fixed costs, but strongly believes a new net-metering rider should also send correct price signals to customers. A balance between fixed-cost recovery and proper price signals must be reached.

Q. What components of the proposed rate do not represent accurate price signals?

A. If the proposed rate is intended to send correct price signals rather than recover fixed costs, the demand component needs to be redesigned. In particular, the proposed demand rate, which is based on the customer's peak demand, regardless of timing or alignment with system peak demand, does not send correct price signals. To illustrate, a peak power draw at 1:00 AM in July would be priced

[24] Direct Testimony of Dallas Dukes pg. 5

the same as a peak power draw at 6:00 PM. A more correct price signal would apply the demand charge specifically during the hours of system peak demand as proposed below.

Q. Does RUCO have any other concerns to the Company's proposed rate?

A. Yes. Any export would be valued at the latest signed solar PPA rate. This means that at any time a single future project can significantly change the economics of a rooftop solar installation. The fact that it is linked to just one project and thus one data point adds concern over the details of that latest PPA. For instance, was it an add-on to an existing array? Did the developer subsidize a portion of the facility for research or publicity ends? Should ratepayers also cut the price paid to other developers if cheaper PPAs are executed 5 years from now?

Q. Are RUCO's proposed options complicated?

A. To potential customers, yes. I find it hard to imagine that customers will understand that the exports of their PV system (which is hard enough to quantify) will be subject to an ever-changing export rate influenced by a PPA proxy of a distant solar PV system.

V. RUCO'S PROPOSED RATE DESIGN AND POLICY FOR DG CUSTOMERS

Q. What is RUCO's proposal concerning DG customers?

A. RUCO agrees that the compensation method for DG needs reform, especially with the growing popularity of DG. However, RUCO believes that the company's proposal can be improved. By creating more options for DG and traditional customers, a win-win solution can be achieved. As such, it is RUCO's goal to find a balanced path that allows the solar industry to mature while maintaining a fair approach for all ratepayers and balancing cost-recovery with pro-conservation price signals. To meet these goals, RUCO proposes making four options available to DG customers going forward. These options are summarized in the table below and described in more detailed in the remainder of my testimony.

DG Rate Option	Description
Advanced DG Rate	• Three-part rate • $11.50 minimum bill • On-peak and off-peak volumetric energy rate, with monthly net metering • On-peak winter and summer demand rate • Customer must remain on rate for full calendar year • $3 metering fee ($0 if RECs are exchanged)
RES Credit Option	• Buy-all, sell-all like transaction. Customer side of meter. • Standard rates apply for all energy consumed on site (customer can select from any available residential rate option) • 20 year fixed credit rate applies to all DG output • Credit rate is adjusted annually for new DG systems through REST plan approval process
DG Volumetric TOU Option	• Two-part rate • $11.50 fixed customer charge • On-peak and off-peak volumetric energy rate, with monthly net metering • Hourly fee applied to all exports • $6 metering fee ($3 if RECs are exchanged)
All Rate Option	• Any full requirements rate plan would be available. • Monthly net metering • Customer chooses one of the following: 1. $/kW Adjustment Fee, based on size of DG system 2. Market Export Rate - Exports are credited at the MCCCG rate • $6 metering fee ($3 if RECs are exchanged)

Q. How does RUCO propose a customer would choose a rate plan and how would this transition be handled?

A. RUCO proposes each of the above rates be available to DG customers at the time of their installation. Customers will be made aware of the different aspects of each rate and the status of grandfathering for that rate. There would be no mandatory or default rate and new DG customers would be able to select one of the available options. Some restrictions may exist, such as a customer not exchanging their RECs with TEP may not be allowed to be on the RES Bill Credit option. Customers would have the option to switch to a different rate plan once per calendar year. However, to avoid gaming, customers that select the Advanced DG TOU rate option would be required to remain on it for one calendar year.

Q. Do these options solve all of RUCO's concerns with DG?

A. No. RUCO would like to begin to solve these concerns by ensuring that rooftop DG can be a neutral cost proposition for ratepayers as soon as possible. Once that milestone is reached RUCO would like to see DG be a net benefit to all ratepayers. Finally, the third milestone, RUCO would like to see a closer cost parity between wholesale grid-connected solar and rooftop solar. While subsidies exist throughout our current regulated policy and rate designs, RUCO believes these cross-subsidies should be quantified, examined and debated. However, simply because other subsidies exist, does not warrant ignoring fast-growing subsidies. RUCO believes incremental and gradual progress to address DG related cross subsidies is fair and will send more accurate price signals to the benefit of all ratepayers.

Q. Please provide details on RUCO's proposed Advanced DG Time of Use rate.

A. The Advanced DG TOU rate is a three-part rate with TOU energy and TOU demand components designed to recover fixed costs while sending more accurate price signals. Fixed costs are recovered through a minimum bill, a variable TOU kWh energy charge, and a TOU kW demand charge over peak hours during summer months. The starting point for designing the DG TOU Rate was to approximate the value of south facing fixed tilt PV on the TEP system. Absent a Commission policy in this regard, I performed a basic calculation of the cost of the next marginal unit of generation needed for the TEP system while still acknowledging the uniqueness and intermittency of solar PV. I set this value as the volumetric offset portion of the plan. I then created a TOU demand charge to send accurate on-peak price signals to the DG adopter while allowing for cost recovery by the Company if the customer fails to reduce peak demand.

Q. How do the time periods for on-peak and off-peak correspond to existing TEP TOU offerings?

A. The months and hours I chose correspond to what the Company currently outlines for their TOU based rates.

Q. Could the Advanced DG TOU be available to non-DG customers?

A. Not at this time. However, RUCO is proposing an optional three-part rate for standard customers should a customer seek a demand charge based rate.

Q. What is a demand charge?

A. A demand charge is a monthly charge based on a customer's peak energy usage for a single billing cycle. Generally, demand charges are calculated by multiplying the highest level of power drawn by a customer over a certain interval during peak demand times (measured in kW) by a demand rate ($/kW). For purposes of the Advanced DG rate, the interval will be the highest peak hour of a given month.

Q. Does RUCO believe demand charges should be applied to general residential customers?

A. In this case, RUCO believes if residential demand charges are implemented, they should be optional for standard residential customers. Furthermore, RUCO believes demand charges should be limited to peak demand hours and peak demand season when system demand is highest. RUCO expresses concern that utilities can easily design demand rates that do not follow this practice, essentially creating demand charges that are essentially unavoidable fixed charges and do not reduce system costs.

A 24/7 demand charge as proposed does not send accurate price signals. The Company's proposal treats all demand equal despite unequal effects of demand on the company's system. A high power draw in the early morning hours of spring would have the same demand charge as a high power draw during a hot mid-evening summer day. This proposal does not reflect costs to the utility, does not represent accurate price signals, and is a poorly designed demand charge.

Because residential demand charges are a departure from traditional volumetric rates, RUCO recommends TEP commit to a customer education plan. Most customers are likely to be unfamiliar with the concept of demand and will require education programs and tools from the Company to understand and respond to the rates. RUCO would like a commitment from TEP to provide customers with these plans in their next DSM plan. Such a commitment should include energy efficiency and demand response programs as discussed in the Commission's technology and innovation workshops.

Q. Please describe in more detail how you determined the volumetric energy rate level for the Advanced DG Rate.

A. I performed a simple, yet fair, calculation of the long-term avoided costs of south facing rooftop PV. I generally followed the outline expressed by Chairman Little in his letter in the Value of Solar docket.[25]

Q. How detailed was your analysis on Value and Cost of DG?

A. As there is no official Commission position or guidance on this issue and due to the fact that many of the possible cost-benefit categories are 1) speculative in nature, 2) rely on policy decisions, 3) are nearly impossible to quantify, and 4) may not have a significant impact on the analysis, RUCO has only examined the major categories of benefits. In addition, RUCO believes that many of the hard to quantify environmental and societal benefits are captured in the preferential treatment

[25] http://images.edocket.azcc.gov/docketpdf/0000167384.pdf

given to resources like solar energy. Treatment such as procurement not tied directly to demand driven need, assumed adoption levels to avoid lumpy generation expenses, fixed payments based on future levelized amounts, and the avoidance of any cost effectiveness tests like energy efficiency measures undergo, are examples of this preferential treatment.

Q. What are the results of your analysis?

A. Using a 30% capacity value from the TEP 2016 preliminary IRP, and cost of a new peaking facility from their 2014 IRP, I obtain approximately 4.25 cents/kWh in possible capacity savings. This includes losses and generation connected transmission. I then added the MCCCG figure from the Company's 2016 REST plan. This yielded 3.9 cents/kWh, which includes losses. I performed another calculation to gain more confidence in this number. I levelized 2015 market pricing from the Palo Verde spot market out 20 years at a 2.5% escalator.[26] I received 3.65 cents/kWh from this calculation, adjusted for 6% losses.[27] When I combined this number with the previous capacity savings figure, I arrived at 7.9 cents/kWh. This represents the approximate long term avoided cost figure for the next marginal rooftop PV system. Meaning that if a solar adopter is paid at this rate, it will offer a breakeven proposition to non-solar ratepayers.

fundamentals

Incremental
Benefits
grid security

[26] Market pricing for EIA can be found here: http://www.eia.gov/electricity/wholesale/
[27] Energy Losses from the 2016 TEP Preliminary IRP https://www.tep.com/doc/planning/2016-TEP-IRP.pdf

Q. Are there other details you would like to share about the DG TOU rate?

A. Yes, the demand charge would be determined by the top hour of demand in a given month during the applicable on-peak window. Also, I propose a minimum bill to recover customer related charges. RUCO initially proposes $11.5 to match the residential TOU rate; however, given that a minimum bill has different dynamics than a fixed charge, RUCO would consider slightly increasing the minimum bill upwards. Finally, if a customer does not exchange renewable energy credits ("RECs") the customer will be assessed a $3 per month meter fee. This lower rate reflects the fact that TEP may not be getting "green" energy from DG customers if the rights to that claim have already been sold or exchanged away to other states or companies.

Q. Please detail the DG Volumetric TOU Option.

A. RUCO proposes a Volumetric TOU option consisting of no tiers, a higher fixed charge, an hourly DG export fee, and monthly banking.

Q. Why does RUCO propose a monthly banking mechanism?

A. With correct hourly and seasonal pricing through the underlying TOU rate, the inherent subsidy of banking is greatly reduced. Therefore, monthly netting instead of hourly can be a more gradual approach to reforming net metering without harmful impacts to non-participant ratepayers.

Q. Why an hourly DG export fee?

A. A two-part volumetric rate over compensates DG adopters because of how fixed costs are recovered. Therefore, grid related fixed costs need to be recovered through a separate mechanism. This export fee concept affords a solar adopter the use of a non-demand charge based plan while still offering some fixed cost recovery.

Q. Why a metering fee?

A. Currently all customers pay for the extra meter solar customers get installed on their premises. The total estimated cost is around $6 per month[28]. About 50% of this cost is covered through the yearly REST budget. Since RECs are used to satisfy the REST compliance targets, the $3 of metering expenses recovered through yearly implementation plans can be fairly avoided if RECs are exchanged. However, non-REST related costs still need to be recovered. It is important to note that the Advanced DG rate does not recover these outside of implementation plan costs because of the improved fixed cost recovery inherent in the rate design. However, if RECs are not exchanged that $3 fee must be still assessed.

Q. Please detail the All Rate Option.

A. The proposed All Rate option consists of an Opt-out Adjustment or a differential market based export rate. Under this rate, DG customers can choose any rate if

[28] FERC, 18 Cfr Part 101 - *Uniform System Of Accounts Prescribed For Public Utilities And Licensees Subject To The Provisions Of The Federal Power Act*

they pay an opt-out fee. The Opt-out Adjustment would be a $/kW fee based on installed PV capacity, and charged monthly. RUCO will determine the level of this fee upon finalization of rate schedules. RUCO also proposes a Market Export Rate option. Again, a DG customer can select any rate but the level of compensation for exports would be set to MCCCG level on an hourly basis.

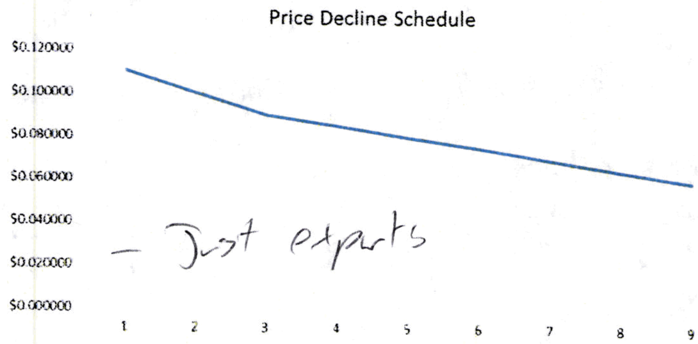
Q. Please detail the RES Credit Option.

A. To meet the Company's residential renewable energy target, the utility needs ~85MW additional distributed generation[29]. To meet this, RUCO proposes a "buy-all sell-all" like credit structure. This credit rate is fixed and linked to REST targets. Based on the 2016 TEP REST implementation plan, TEP requires about 85 MW residential DG to meet the Commission's 2025 target. It is likely this number will change, reflective of the number of systems installed during the course of the rate case and whether the Commission chooses to recognize systems that have not exchanged their REC's.

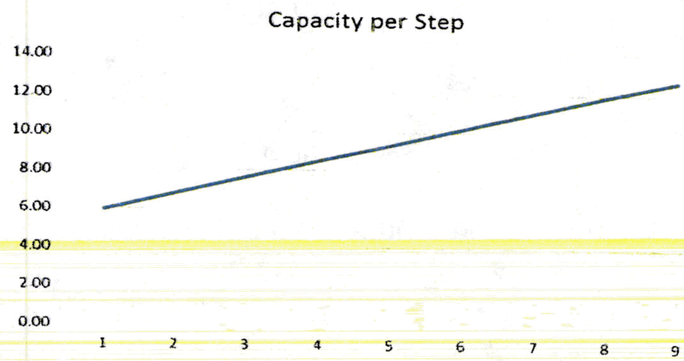
This RES credit option would work conceptually much like the declining upfront incentives, the Commission used a few years ago. A credit would begin at a set rate (RUCO proposes close to current retail) and gradually declines in a predictable way over time. RUCO proposes to start at a decline rate pegged to historical system price decreases. Below is an illustration of the concept and the step downs RUCO proposes:

[29] 2016 TEP REST plan - E-01933A-15-0239

Capacity per Tranche	Price per Tranche
6.0	$0.110
6.8	$0.100
7.7	$0.090
8.5	$0.085
9.4	$0.080
10.3	$0.075
11.1	$0.070
12.0	$0.065
12.8	$0.060



– Just exports



A fixed rate for 20 years will avoid grandfathering issues and provide predicable financing for adopters. Systems taking service under the RES credit option would be on the customer side of the meter and receive a monthly bill credit monthly. This would prevent the rate design from impacting the economics of the installation and electrons produced by the system would serve local load of the customer.

The Commission and stakeholders would have the opportunity to recommend and adjust the terms in each annual REST plan. This would allow changes to the payment of future customers as well as accounting for possibly increasing payments based on system orientation or inverter capabilities. To participate in this rate option, customers must assign RECs to the Company.

30 P

Q. How would the RES Credit Option interface with the Advanced DG TOU rate?

A. Similar to the Upfront Incentive programs a few years ago, the RES credit rate will predictably decline as more solar capacity comes online. This would include capacity installed under the Advanced DG TOU rate and would contribute to capacity step downs despite not receiving the RES credit.

Q. What is RUCO's anticipated ratepayer acceptance of each of the DG rate options?

A. RUCO believes the most popular rate will be the RES Bill Credit Option, particularly early in the program due to the declining credit structure. During the time that RES Bill Credit Option remains the most popular, the industry can prepare for the Advanced DG TOU rate. With the credit rate beginning at $0.11/kWh this option is most similar to the current rate design. It is likely that some customers will immediately choose the Advanced DG TOU rate, particularly customers with more knowledge and tools to control peak load. The choice of rates allows the solar industry to mature rather than deal with a new defaulted rate. The solar industry will have the ability of developing business plans around the Advanced DG TOU rate that may be more advantageous than other proposed options.

The DG TOU Option creates a floor for the offset rate for DG customers. The Bill Credit Option will decline and approach the Advanced DG TOU rate as more customers take service under the RES Bill Credit Option. This is beneficial for the industry as it can begin to rely on the on-peak price signals provided by the

Advanced DG TOU rate. The All Rate options further supplement these offerings. The DG opt out adjustment levels the economic playing field between DG and standard rates while the Market Export Option would be popular among DG customers with small systems and large load. These options were designed to address the concerns of DG advocates who have insisted that DG customers "not be treated differently." The Market Export option provides exactly that.

Q. Please describe RUCO's view on grandfathering existing solar customers

A. RUCO believes there are several options to fairly grandfather DG customers. Customers that installed DG during the REST UFI program era should continue to be grandfathered at current rates, no questions asked. These customers were incentivized to install DG to ensure utilities met Renewable Energy Standard targets. Following the conclusion of the incentive program, customers were advised of possible changes that could affect their investment in DG. Despite these warnings, RUCO feels many customers did not fully understand the effect a rate design change could bring. Therefore, changes to these customers must be small and incremental and generally grandfathered up to the date of the UNS rate case decision. To ensure future customers are fully aware of the possible economic implications of tariff reform, new disclaimers must be crafted after the UNS decision to explain the choices and economics they may face should those polices be adopted in the TEP case.

Q. Does Grandfathering also impact TEP's residential utility owned rooftop program or TORS?

A. Yes it does. To explain, if the cost shift of existing NEM systems changes and the TEP owned systems become more expensive to non-participants, then TEP will have adjust downward the amount TEP recovers from ratepayers. I plan to address more on this topic in the next round of testimony once I receive answers to a pending data request.

Q. Any other issue you would like to address?

A. Yes, on my preliminary rate designs attached to this testimony. In designing the rates, I tried to keep the prices grounded to the economics of marginal supply side resources. Meaning, I try to send price signals not too much greater or less than comparably timed supply side resources. For example, my demand charges and peak rates are both within the range of the cost of a new combustion turbine peaker.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBIT LH-1

Lon Huber
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lhuber@strategen.com

EDUCATION

January 2010 – May 2011
Eller College of Management - University of Arizona
Masters of Business Administration (MBA)

August 2005 – May 2009
School of Government & Public Policy - University of Arizona
Bachelor of Science - Public Policy and Management

RELEVANT WORK EXPERIENCE

Strategen Consulting
Director –March 2015 to present

Arizona's Residential Utility Consumer Office (RUCO)
Special Projects Advisor and former consultant – April 2013 to March 2015

- Responsibilities: policy analysis and design, advocacy, case testimony, constituent outreach, and financial analysis.
    - Team lead on net metering, utility-owned rooftop solar, and new resource procurement policies.
    - Graduate of NARUC Rate Design School, 2014

Suntech America
Manager, Regional Policy – September 2011 to December 2012

- Point person for the company in every key state solar market except California.
    - Worked to balance cost effective utility-scale solar with state distributed generation policy goals.
    - Elected by SEIA member companies to be the state lead in Arizona.

TFS Solar
Government Affairs – September 2010 to September 2011

- Created a solar financing program for faith based organizations in Tucson.
- Instrumental in forming the Southern Arizona Solar Standards Board.
- Advocated for polcies in front of ACC.

Arizona Research Institute for Solar Energy at the University of Arizona
"Founding employee" and Policy Program Associate – August 2007 to September 2010

- Helped build the institute while gaining experience with the technical attributes and challenges of various energy technologies.

Lon Huber

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Congressional Fellow – D.C.

January 2009 to May 2009

- Responsibilities included weekly memos to the Congress member on energy issues, forming energy related legislation (Solar Schools Act - H.R. 4967), and creating educational presentations on energy.

COMMUNITY INVOLVEMENT

- Appointed to the Arizona Governor's Solar Task Force, 2013
- Chairman - Southern Arizona Regional Solar Partnership at the Pima Association of Governments, 2011
- Founding Chairman - University of Arizona Green Fund, 2010 to 2011
- Member of UA President's Campus Sustainability Advisory Board, 2008 to 2011
- Big Brother for a child in special needs program - Tucson Big Brothers Big Sisters, 2006 to 2008

AWARDS AND HONORS

- *Arizona Daily Star's* "40 Under 40" winner for leadership, community impact, and professional accomplishment, 2011
- University of Arizona Honors College Young Alumni Award Winner, 2011
- Outstanding Professional Staff Member – University of Arizona, 2010
- Arizona Foundation Outstanding Senior Award for the Eller College of Management, 2009
- Honors College Pillars of Excellence Award, March 2009
- Congressional Recognition Award, May 2008

EXHIBIT LH-2

**THE NATIONAL ASSOCIATION OF
STATE UTILITY CONSUMER ADVOCATES
RESOLUTION 2015-1**

OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

Whereas, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer's usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

Whereas, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are "fixed" and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

Whereas, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

Whereas, gas and electric utilities' own embedded cost of service studies,[1] in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

Whereas, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,[2] in some instances; and

Whereas, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

Whereas, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

Whereas, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains,"[3] low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts;[4] and

Whereas, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts;[5] and

Whereas, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts;[6] and

Whereas, data from the U.S. Department of Energy's Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,[7] thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S;[8] and

Whereas, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

Whereas, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer's utility bill consisting of variable usage charges, customers' incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

Whereas, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

Whereas, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer's utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

Now, therefore, be it resolved, that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers;

Be it further resolved, that NASUCA *opposes* proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

Be it further resolved, that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

Be it further resolved, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

Be it further resolved that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015
Philadelphia, Pennsylvania

No Vote: Wyoming
Abstention: Vermont

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[1]*See, e.g.,* Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates,* PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company,* AG Ex. 1.0 at 12-13, *citing* ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

[2]ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

[3]The U.S. Energy Information Administration's Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as "reportable domains."

[4]*See* Wis. Pub. Serv. Com'n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natur4al Gas Rates,* Public Comments of John Howat, National Consumer Law Center, October 3, 2014, *citing* 2009 U.S. EIA Residential Energy Consumption Survey data by "Reportable Domain" at 5-6.

[5] *Id.* at 7-8.

[6] U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

[7] *See* ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates,* AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

[8] U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

EXHIBIT LH-3

Default TOU for Full Requirements

Basic Monthly Service Charge	$11.50

Delivery (kWh)	Summer	Winter
On-Peak	0.18	0.10
Off-Peak	0.06	0.05

Base Power	Low	Medium	High
Tier Floor (kWh)	0	501	1001
Tier Ceiling (kWh)	500	1000	
Rate	0.02	0.03	0.045

Peak Hours	Summer	Winter
Peak Hour Start	3:00 PM	6:00 AM
Peak Hour End	7:00 PM	9:00 AM

Partial Requirements Volumetric TOU Rate

Basic Monthly Service Charge	$11.50
Solar Meter Fee	$6.00
Meter Fee if RECs are Exchanged	$3.00

Delivery (kWh)	Summer	Winter
On-Peak	0.18	0.10
Off-Peak	0.04	0.035

Base Power (kWh)	Low	Medium	High
Rate	0.036	0.036	0.036

Peak Hours	Summer	Winter	Winter
Peak Hour Start	2:00 PM	6:00 AM	6:00 PM
Peak Hour End	8:00 PM	9:00 AM	9:00 PM

Hourly Export Charge (kWh)	2 cents/kWh

Three Part Optional Rate

Basic Monthly Service Charge	$11.50
Meter Fee if no RECs are Exchanged	$3.00

Demand Charges	Summer	Winter	Summer Shoulder	Winter Shoulder	kW Break Point
Below Break Point	$4	$2	$0	$0	4.5
Above Break Point	$12	$4	$0	$0	

Delivery (kWh)	Summer	Winter
On-Peak	0.16	0.09
Off-Peak	0.03	0.02

Base Power (kWh)	Low	Medium	High
Rate	0.036	0.036	0.036

	Summer	Winter
Start Month	May	October
End Month	September	April

Peak Hours	Summer	Winter
Peak Hour Start	3:00 PM	6:00 AM
Peak Hour End	7:00 PM	9:00 AM

Advanced DG Rate

Minimum Bill	$11.50
Meter Fee if no RECs are Exchanged	$3.00

Demand Charges	Summer	Winter
$/kW	$16	$6

Delivery (kWh)	Summer	Winter
On-Peak	0.16	0.09
Off-Peak	0.03	0.02

Base Power (kWh)	Low	Medium	High
Rate	0.036	0.036	0.036

	Summer	Winter
Start Month	May	October
End Month	September	April

Peak Hours	Summer	Winter	Winter
Peak Hour Start	2:00 PM	6:00 AM	6:00 PM
Peak Hour End	8:00 PM	9:00 AM	9:00 PM